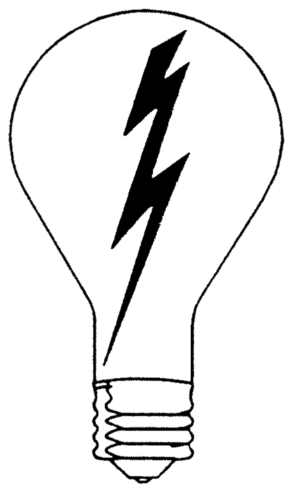
YEAR 1993

ANNUAL REPORT

OF

PACIFICORP

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MONTANA 59620-2601

REVISED OCTOBER 20, 1992

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Instructions

General

1. A computer disk, formatted with DOS Version 5.0, is being provided for your convenience. The files were created using the DOS version of Lotus 3.1 and were saved with the wk1 extension. WYSIWYG was used as an addin, these files have the fmt extension. Separate files were created for each page. Where multiple schedules are on one page, one file was created. The naming convention of the files is representative of the schedules contained on a page (for example, Schedules 1 and 2 are sch1&2.wk1, Schedule 3 is sch3.wk1). Use of the disk is optional. The disk shall be returned when the report is filed.

2. All forms shall be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed.

3. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses (   ).

4. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

5. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

6. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

7. All companies owned by another company shall attach a corporate structure chart of the holding company.

8. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

9. The following schedules shall be filled out with information on a total company basis:

Schedules 1 through 5
Schedules 7 and 8
Schedule 15
Schedule 18
Schedules 23 through 27
Schedules 34 and 35

All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

10. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedules.

11. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 9, 18, and 23
1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 9A, etc.)

Schedule 6
1. Each sale, transfer or retirement of utility plant with a total combined value (higher of original book cost or selling price) of $50,000 or more assigned/allocated to Montana shall be reported on this schedule. Each plant item which requires a mortgage release must be reported regardless of its value.

Schedules 7 and 8
1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedule 13

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 15

1. Companies with defined contribution plans do not need to complete lines 25 through 28.

2. Companies with defined benefit plans must complete the entire form. Lines 10 through 23 shall be filled out using FASB 87 guidelines. Line 25 refers to the minimum required contribution under ERISA. Line 27 refers to the maximum amount deductible for tax purposes.

Schedule 16

1. All changes in the employee benefit plans shall be explained in a narrative on lines 16 through 19. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 16 through 19. All assumptions used in quantifying cost containment results shall be disclosed.

2. Lines 36 through 46 on page 1 and lines 18 through 28 on page 2 shall be filled out using FASB 106 guidelines.

Schedule 17

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock

appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated only for the months that earnings and dividends are entered. The price/earnings ratio shall be calculated using the average of the high and low market prices for the given month and the quarterly earnings times 4.

3. Enter the actual year end market price in the "TOTAL Year End" row, this amount shall be used to calculate the year end price/earnings ratio. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 28

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

3. Indicate, for each adjustment on lines 28 through 49, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 29

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 32

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 33

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 35

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.

   Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages exceeding one hour which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 36

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Sch. 1	IDENTIFICATION

Legal Name of Respondent: PacifiCorp

Name Under Which Respondent Does Business: Pacific Power / Utah Power

Date Utility Service First Offered in Montana: May 21, 1954 (Date of Mountain States States Power Company merger with Pacific Power)

Person Responsible for Report: Anne E. Eakin – Assistant Vice President

Telephone Number for Report Inquiries: (503) 464-5065

Address for Correspondence Concerning Report:

Pacific Power
1228 Public Service Building
920 S. W. Sixth Avenue
Portland, Oregon 97204

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

Sch. 2	BOARD OF DIRECTORS		
	Director Name & Address (City, State)		Remuneration
1	Keith R. McKennon (Chairman) (1)	Portland, Oregon	48,541
2	A. M. Gleason (Vice Chairman) (1)	Portland, Oregon	(2)
3	Frederick W. Buckman (1)(3)	Portland, Oregon	-
4	C. M. Bishop, Jr.	Portland, Oregon	51,146
5	C. Todd Conover	Cupertino, California	45,536
6	Richard C. Edgley	Salt Lake City, Utah	59,548
7	John C. Hampton	Portland, Oregon	60,294
8	Stanley K. Hathaway	Cheyenne, Wyoming	33,995
9	Nolan E. Karras	Roy, Utah	45,586
10	Don M. Wheeler	Salt Lake City, Utah	49,346
11	Nancy Wilgenbusch	Marylhurst, Oregon	37,745
12	Don C. Frisbee (Chairman Emeritus)(4)	Portland, Oregon	160,800
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22	(1) Elected February 1994		
23	(2) No remuneration as a director, officer of the Company		
24	during 1993		
25	(3) President and Chief Executive Officer of the Company		
26	(4) Retired February 1994		

Sch. 3

OFFICERS

Title	Department Supervised	Name
President and Chief Executive Officer		Frederick W. Buckman
President – Pacific Power		Paul G. Lorenzini
President – Utah Power		Verl R. Topham
Senior Vice President and Chief Financial Officer		William J. Glasgow
Senior Vice President	Pacific Power Operations	Diana E. Snowden
Senior Vice President	Engineering	Harry A. Haycock
Senior Vice President	Accounting, Taxes and Financial Planning	Daniel L. Spalding
Senior Vice President	Assistant to the President	John A. Bohling
Senior Vice President	Administration	Shelly R. Faigle
Senior Vice President	Power Systems, Mergers and Acqusitions, Regulation and Bulk Power Planning	Dennis P. Steinberg
Executive Vice President	Utah Power Operations	John E. Mooney
Controller		Jacqueline S. Bell
Vice President	Thermal Resources	William C. Brauer
Vice President	Summit Region	Thomas W. Forsgren
Vice President	Public Affairs, Communications and Environmental Policy	Thomas J. Imeson
Vice President	Wyoming Region	Thomas A. Lockhart
Vice President	Finance	Robert F. Lanz
Vice President	Information Management	Stan M. Marks
Vice President and Corporate Secretary	Shareholder Services	Sally A. Nofziger
Vice President	Human Resources	Michael J. Pittman
Vice President	Fuel Resources	Ernest E. Wessman
Vice President	Rocky Mountain Region	Richard D. Westerber
Vice President	Business Process Improvement and Strategic Planning	Dave Hoffman

OFFICERS (Continued)

	Title	Department Supervised	Name
54	Assistant Secretary and Controller		H. Arnold Wagner
55			
56	Vice President		Richard T. O'Brien
57			
58	Treasurer		William E. Peressini
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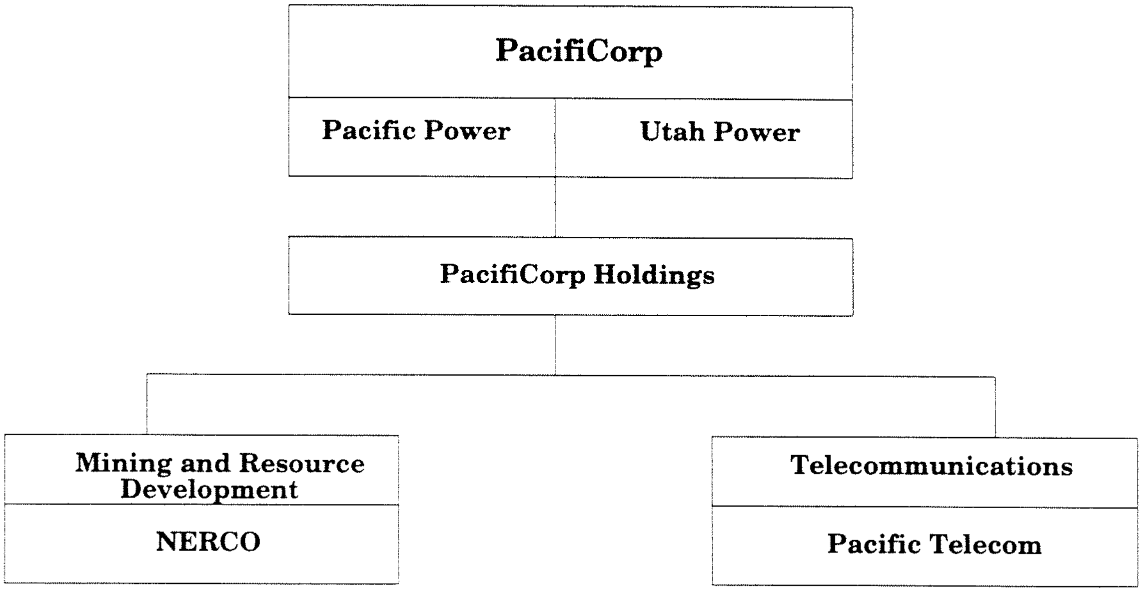
Sch. 4

CORPORATE STRUCTURE

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	PacifiCorp Holdings, Inc.	Holding company	114,880,792	100.29%
3	North American Energy Services Co.	Maintenance of Steam Plants	(17,278)	-0.02%
5	Pacific Relocation Service Company	Employee relocations	(98,656)	-0.09%
7	PacifiCorp D.C. Limited	Federal legislative and	(210,687)	-0.18%
8		regulatory representation		
53	TOTAL		114,554,171	100.00%

THE ORGANIZATION

The Company is a diversified electric utility that conducts its retail electric utility business through two divisions, Pacific Power and Utah Power, and engages in power production and sales on a wholesale basis under the name PacifiCorp. The chart below sets forth the corporate structure of the PacifiCorp Group's three principal businesses during the first 5 months of 1993. The corporate structure during the last 7 months of 1993 is shown on the following page.



PacifiCorp Holdings was formed to hold the stock of the Company's principal subsidiaries and to facilitate the conduct of business not regulated as electric utilities. Initially named Inner PacifiCorp, this holding company was renamed PacifiCorp Holdings in 1992. Through PacifiCorp Holdings, the Company indirectly owns:

NERCO (82%), a natural resource company that is a significant producer of coal, gold and silver in North America, and of natural gas and oil in the Gulf Coast region of the United States, and is also engaged in the exploration for and development of precious metals, gas and oil. In 1993, PacifiCorp announced the sale of NERCO. That sale to a subsidiary of RTZ America, Inc. closed June 2, 1993.

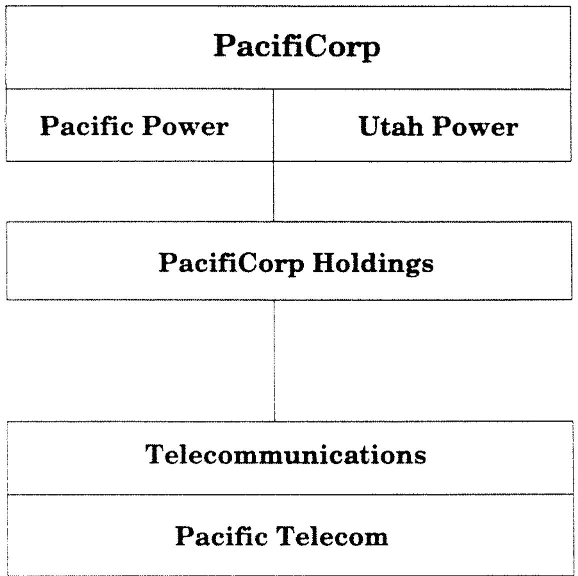
Pacific Telecom (87%), a business providing local telephone service and access to the long distance network in Alaska, seven other western states and three midwestern states, providing intrastate and interstate long distance communication services in Alaska, providing cellular mobile telephone services, and engaging in the sale of capacity in a submarine fiber-optic cable between the U. S. and Japan.

In addition, PacifiCorp Holdings holds PacifiCorp Financial Services (100%), a business offering certain specialized financial services, including aviation financing, computer leasing and real estate investments. PacifiCorp Holdings also has wholly-owned subsidiaries that are engaged in other businesses, including independent power production and co-generation.

The following pages provide an organization chart, in columnar form, of PacifiCorp and its subsidiaries. For each subsidiary, the percentage of ownership held by its parent company is listed as well as the state of incorporation. The listing of subsidiaries also contains a numerical reference for each subsidiary in the organization. This reference number is attached to each affiliated interest entity throughout the report to facilitate cross-referencing.

THE ORGANIZATION AT DECEMBER 31, 1993

The corporate structure during the last 7 months of 1993.



SUBSIDIARIES OF THE COMPANY

PacifiCorp Holdings, Inc., a wholly-owned subsidiary of the Company and a Delaware corporation, has the following subsidiaries:

	Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
	PACE Group, Inc.	100%	Oregon
2	PacifiCorp Financial Services, Inc.	100%	Oregon
	Color Spot, Inc.	100%	Oregon
	Pacific Development, Inc.	100%	Oregon
	Pacific Harbor Capital, Inc.	100%	Delaware
6	Pacific Relocation Service Company	100%	Oregon
	PacifiCorp Capital, Inc.	100%	Virginia
	PacifiCorp Credit, Inc.	100%	Oregon
	Vermont Castings, Inc.	100%	Vermont
3	Pacific Generation Company	100%	Oregon
	Energy National, Inc.	100%	Utah
	ONSITE Energy, Inc.	100%	Oregon
4	Pacific Telecom, Inc.	87%	Washington
5	PacifiCorp Trans, Inc.	100%	Oregon

Pacific Telecom, Inc., an 87% owned subsidiary of PacifiCorp Holdings, Inc., and a Washington corporation, has the following subsidiaries:

Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
Alascom, Inc.	100%	Alaska
Cascade Autovon Company	100%	Washington
Eagle Telecommunications, Inc./Colorado	100%	Colorado
Eagle Valley Communications Corporation	100%	Colorado
Gem State Utilities Corporation	92%	Idaho
Indianhead Communications Corporation	100%	Wisconsin
Inter Island Telephone Company, Inc.	100%	Washington
International Communications Holdings, Inc.	85%	Delaware
North-West Cellular, Inc.	100%	Nevada
North-West Telecommunications, Inc.	100%	Nevada
Northland Telephone Company	100%	Minnesota
North-West Telephone Company	100%	Wisconsin
Postville Telephone Company	100%	Wisconsin
The Footville Telephone Company	100%	Wisconsin
Sullivan Telephone Company	100%	Wisconsin
Turtle Lake Telephone Company, Inc.	100%	Wisconsin

Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
Northwestern Telephone Systems, Inc.	99%	Oregon
Pacific Telecom Cable, Inc.	80%	Delaware
Pacific Telecom Cellular, Inc.	100%	Delaware
Pacific Telecom Cellular of Alaska, Inc.	100%	Alaska
Pacific Telecom Cellular of I-5, Inc.	100%	Washington
Pacific Telecom Cellular of Michigan, Inc.	100%	Michigan
Pacific Telecom Cellular of Minnesota, Inc.	100%	Minnesota
Pacific Telecom Cellular of Oregon, Inc.	100%	Oregon
Pacific Telecom Cellular of South Dakota, Inc.	100%	South Dakota
Pacific Telecom Cellular of Washington, Inc.	100%	Washington
Pacific Telecom Cellular of Wisconsin, Inc.	100%	Wisconsin
Pacific Telecom Transmission Services, Inc.	100%	Oregon
Price County Telephone Cellular, Inc.	100%	Wisconsin
PTI Broadcasting, Inc.	100%	Oregon
PTI Harbor Bay, Inc.	100%	Washington
Bay Area Teleport, Inc.	100%	Delaware
Rib Lake Cellular for Wisconsin RSA #2, Inc.	100%	Wisconsin
Shell Lake Telephone Company, Inc.	100%	Wisconsin
Telephone Utilities of Alaska, Inc.	100%	Alaska
Telephone Utilities of Eastern Oregon, Inc.	100%	Oregon
Telephone Utilities of Northland, Inc.	100%	Alaska
Telephone Utilities of Oregon, Inc.	100%	Oregon
Telephone Utilities of Washington, Inc.	100%	Washington
Telephone Utilities of Wyoming, Inc.	100%	Wyoming
Thorp Telephone Company	100%	Wisconsin
UpSouth Corporation	100%	Georgia
Wayside Telecom, Inc.	100%	Wisconsin
The Wayside Telephone Company	100%	Wisconsin

The Company also has the following subsidiaries:

	Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
7	Centralia Mining Company	100%	Washington
8	Energy West Mining Company	100%	Utah
9	Glenrock Coal Company	100%	Wyoming
	Interwest Mining Company	100%	Oregon
	Pacific Minerals, Inc.	100%	Wyoming
	Bridger Coal Company, a joint venture	66.67%	Wyoming
10	Williams Fork Company (owned by PacifiCorp)	19.7%	Colorado
11	Microrim (owned by Pacific Telecom)	16%	Washington
	Pyro Pacific Operating Company (owned by Pacific Mt. Poso Corp., a subsidiary of Pacific Generation Company)	7.5%	California

	Name of PacifiCorp Holdings, Inc. subsidiary sold during 1993		
1	NERCO, Inc.	82%	Oregon

Sch. 5

CORPORATE ALLOCATIONS

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Corporate Management Fee		Three Factor Method			
2	$2,430,431	January thru May (1)	62.0% to Electric Utility Operations			
3	$4,224,636	June thur December (1)	72.0% to Electric Utility Operations			
4						
5	Electric Utility Portion					
6	$4,548,605			77,840	1.7113%	4,470,765
7						
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16	(1) Change in allocation percentage due to the sale of the Company's mining and resource development					
17	business, NERCO, Inc.					
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35	TOTAL			77,840		4,470,765

Sch. 6

ASSET SALES, TRANSFERS & RETIREMENTS AFFECTING MT UTILITY

	Plant Description	Plant Account Number	Work Order Number	Item Ever Rate Based (Y or N)	Trans. Date	Trans. Type (S,T,R)	Affiliate Trans. (Y or N)	Mortgage Release (Y or N)	Trans. Amount (000)	Gain Loss (000)
1	Sell Libby Geneerating Facilities	353	4281	Y	Sept-93	S	N	N	(190)	
2	Sell Libby Geneerating Facilities	361	4281	Y	Sept-93	S	N	N	(3)	
3	Sell Libby Geneerating Facilities	362	4281	Y	Sept-93	S	N	N	(3)	
4										
5	Repair Tornado Damage	355	2289	Y	Dec-93	R	N	N	(72)	
6	(Decker-Wyomont 230KV Line)	356	2289	Y	Dec-93	R	N	N	(23)	
7										
8	7.5 MVA Transformer	362	749991	Y	Apr-93	T	N	N	96	
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Sch. 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% Total Affil. Revs.	Charges to MT Utility
Pacific Telecom	Shareholder Service Records	Cost	339,871	0.05%	5,816
	Telephone Equipement	Cost	931	0.00%	931
	Telephone Svc & Pole Attachments	Cost	144,497	0.02%	14,641
NERCO	Fuel Stock	Cost	3,088,991	N/A (1)	51,407
PacifiCorp Financial Services	Leased Office Space	Cost	607,295	0.34%	10,241
PacifiCorp Trans, Inc.	Corporate Air Transportation	Cost	4,897,513	77.98%	89,867
Pacific Relocation	Moving, Mngmnt & Admin Fees	Cost	128,721	19.91%	1,978
Centralia Mining Company	Mine Mngmnt & Mining Svcs	Cost	44,827,911	N/A (2)	746,026
Energy West Mining Company	Mine Mngmnt & Mining Svcs	Cost	118,293,110	N/A (2)	1,968,634
Glenrock Coal	Fuel Stock	Cost	27,350,745	N/A (2)	455,171
Williams Fork Company	Mine Mngmnt & Mining Svcs	Cost	7,360,013	N/A (2)	122,485
Microrim	Software	Cost	0	N/A (3)	0

(1) A return analysis is not included. On June 2, 1993, NERCO was sold to a subsidiary of the RTZ Corportation; therefore, no financial statements were available to determine any profit or loss for the year ended December 31, 1993.

(2) This company is not evaluated on a stand-alone basis. Therefore, no balance sheet or income statement is available.

(3) PacifiCorp owns less than 20% of Microrim and holds its interest as a cost-based investment. Microrim did not provide an annual report. PacifiCorp wrote off the investment in Microrim in 1993.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% Total Affil. Exp.	Revenues to MT Utility
Pacific Telecom	Printing Services	Cost	6,089	0.0011%	0
	Engineering Maps	Cost	682	0.0001%	0
	Pole Contact Rental	Cost	123,132	0.0217%	0
NERCO	Printing Services	Cost	71	N/A (1)	0
PacifiCorp Financial Services	Printing Services	Cost	656	0.0004%	0
Pacific Generation	Printing Services	Cost	399	N/A (2)	0
PacifiCorp Trans, Inc.	Printing Services	Cost	2,062	0.0353%	0
	Accounting & Accts Payable Svcs	Cost	18,000	0.3085%	0
	Office Rent	Cost	2,846	0.0488%	0
Pacific Relocation	Printing Services	Cost	445	0.0596%	0

(1) A return analysis is not included. On June 2, 1993, NERCO was sold to a subsidiary of the RTZ Corportation; therefore, no financial statements were available to determine any profit or loss for the year ended December 31, 1993.

(2) Pacific Generations's financial statements for 1993 were not available by June 1, 1994.

NOTE: Transactions involving services provided by PacifiCorp to affiliated companies are charged to work orders using account 186, Miscellaneous Deferred Debits - Other Work in Progress. On a monthly basis, the balances in each work order are analyzed and cleared to receivable account 146. The affiliate is then billed for the amount due. When payment is received from the affiliate, the receivable is extinguished. Thus, billings to affiliates do not result in charges to accounts affecting ratepayers.

Sch. 9	MONTANA UTILITY INCOME STATEMENT				
		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	38,472,022	43,175,949	12.23%
2					
3		Operating Expenses			
4	401	Operation Expenses	19,911,551	20,598,925	3.45%
5	402	Maintenance Expenses	2,471,711	3,048,811	23.35%
6	403	Depreciation Expenses	3,994,694	3,910,145	-2.12%
7	404-405	Amortization of Electric Plant	161,730	180,543	11.63%
8	406	Amort. of Plant Acquisition Adjustments	72,765	101,517	39.51%
9	407	Amort. of Property Losses, Unrecovered Plant	0	38,703	
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	1,386,989	1,508,648	8.77%
12	409.1	Income Taxes - Federal	1,649,811	2,211,566	34.05%
13		- Other	359,033	270,662	-24.61%
14	410.1	Provision for Deferred Income Taxes	1,494,970	1,852,509	23.92%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(605,403)	(742,537)	22.65%
16	411.4	Investment Tax Credit Adjustment	0	0	
17	411.6	(Less) Gains from Disposition of Utility Plant		(459)	
18	411.7	Losses from Disposition of Utility Plant		1,175	
19					
20		TOTAL Utility Operating Expenses	30,897,852	32,980,208	6.74%
21					
22		NET UTILITY OPERATING INCOME	7,574,170	10,195,741	34.61%

Sch. 10	MONTANA REVENUES				
		Account Number & Title	Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	14,041,531	15,893,729	13.19%
3	442	Commercial & Industrial - Small	10,179,308	10,921,864	7.29%
4		Commercial & Industrial - Large	7,148,965	7,741,853	8.29%
5	444	Public Street & Highway Lighting	138,225	140,393	1.57%
6	445	Other Sales to Public Authorities	0	0	
7	446	Sales to Railroads & Railways			
8	448	Interdepartmental Sales	(10)	7,708	
9					
10		TOTAL Sales to Ultimate Consumers	31,508,019	34,705,547	10.15%
11	447	Sales for Resale	6,754,597	8,011,432	18.61%
12					
13		TOTAL Sales of Electricity	38,262,616	42,716,979	11.64%
14	449.1	(Less) Provision for Rate Refunds	(45,662)	0	
15					
16		TOTAL Revenue Net of Provision for Refunds	38,216,953	42,716,979	11.77%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	15,663	18,917	20.78%
19	451	Miscellaneous Service Revenues	3,530	8,721	147.03%
20	453	Sales of Water & Water Power	2,277	1,790	-21.38%
21	454	Rent From Electric Property	184,369	174,153	-5.54%
22	455	Interdepartmental Rents	0	0	
23	456	Other Electric Revenues	49,230	255,389	418.77%
24					
25		TOTAL Other Operating Revenues	255,069	458,970	79.94%
26					
27		Total Electric Operating Revenues	38,472,022	43,175,949	12.23%

MONTANA OPERATION & MAINTENANCE EXPENSES

Account Number & Title		Last Year	This Year	% Change
	Power Production Expenses			
Steam Power Generation				
Operation				
500	Operation Supervision & Engineering	185,412	229,811	23.95%
501	Fuel	8,156,562	8,050,558	-1.30%
502	Steam Expenses	361,656	412,489	14.06%
503	Steam from Other Sources	62,670	31,761	-49.32%
504	(Less) Steam Transferred - Cr.	0	0	
505	Electric Expenses	163,626	215,108	31.46%
506	Miscellaneous Steam Power Expenses	412,500	446,495	8.24%
507	Rents	1,585	805	-49.20%
	TOTAL Operation - Steam	9,344,011	9,387,028	0.46%
Maintenance				
510	Maintenance Supervision & Engineering	223,379	285,665	27.88%
511	Maintenance of Structures	104,074	136,429	31.09%
512	Maintenance of Boiler Plant	688,174	844,796	22.76%
513	Maintenance of Electric Plant	170,631	218,927	28.30%
514	Maintenance of Miscellaneous Steam Plant	271,564	163,065	-39.95%
	TOTAL Maintenance - Steam	1,457,821	1,648,882	13.11%
	TOTAL Steam Power Production Expenses	10,801,833	11,035,910	2.17%
Nuclear Power Generation				
Operation				
517	Operation Supervision & Engineering	25,085	0	-100.00%
518	Nuclear Fuel Expense	6,457	0	-100.00%
519	Coolants & Water	869	0	-100.00%
520	Steam Expenses	5,860	0	-100.00%
521	Steam from Other Sources	0	0	
522	(Less) Steam Transferred - Cr.	0	0	
523	Electric Expenses	970	0	-100.00%
524	Miscellaneous Nuclear Power Expenses	39,073	73	-99.81%
525	Rents	0	0	
	TOTAL Operation - Nuclear	78,313	73	-99.91%
Maintenance				
528	Maintenance Supervision & Engineering	10,295	0	-100.00%
529	Maintenance of Structures	2,356	0	-100.00%
530	Maintenance of Reactor Plant Equipment	(8,475)	0	-100.00%
531	Maintenance of Electric Plant	640	0	-100.00%
532	Maintenance of Miscellaneous Nuclear Plant	4,382	0	-100.00%
	TOTAL Maintenance - Nuclear	9,198	0	-100.00%
	TOTAL Nuclear Power Production Expenses	87,511	73	-99.92%

	Account Number & Title	Last Year	This Year	% Change
1	**Power Production Expenses -continued**			
2	Hydraulic Power Generation			
3				
4	Operation			
5	535 Operation Supervision & Engineering	9,708	15,792	62.68%
6	536 Water for Power	1,341	255	-80.99%
7	537 Hydraulic Expenses	62,102	61,679	-0.68%
8	538 Electric Expenses	59,073	69,446	17.56%
9	539 Miscellaneous Hydraulic Power Gen. Expe	26,176	116,298	344.30%
10	540 Rents	169	(226)	-233.99%
11				
12	TOTAL Operation - Hydraulic	158,569	263,244	66.01%
13				
14	Maintenance			
15	541 Maintenance Supervision & Engineering	4,317	4,568	5.81%
16	542 Maintenance of Structures	14,359	8,850	-38.37%
17	543 Maint. of Reservoirs, Dams & Waterways	29,898	26,524	-11.28%
18	544 Maintenance of Electric Plant	29,504	45,601	54.56%
19	545 Maintenance of Miscellaneous Hydro Plant	19,642	29,570	50.55%
20				
21	TOTAL Maintenance - Hydraulic	97,719	115,113	17.80%
22				
23	TOTAL Hydraulic Power Production Expense	256,288	378,357	47.63%
24				
25	Other Power Generation			
26				
27	Operation			
28	546 Operation Supervision & Engineering	58	230	297.89%
29	547 Fuel	37,151	39,854	7.28%
30	548 Generation Expenses	339	1,400	312.87%
31	549 Miscellaneous Other Power Gen. Expense	9	234	2393.63%
32	550 Rents	0	0	
33				
34	TOTAL Operation - Other	37,557	41,718	11.08%
35				
36	Maintenance			
37	551 Maintenance Supervision & Engineering	56	227	305.09%
38	552 Maintenance of Structures	0	7	
39	553 Maintenance of Generating & Electric Plan	257	562	118.27%
40	554 Maintenance of Misc. Other Power Gen. Pl	130	558	329.74%
41				
42	TOTAL Maintenance - Other	443	1,353	205.42%
43				
44	TOTAL Other Power Production Expenses	38,000	43,071	13.34%
45				
46	Other Power Supply Expenses			
47	555 Purchased Power	2,972,001	4,689,466	57.79%
48	556 System Control & Load Dispatching	99,995	92,531	-7.46%
49	557 Other Expenses	227,617	188,817	-17.05%
50				
51	TOTAL Other Power Supply Expenses	3,299,613	4,970,814	50.65%
52				
53	TOTAL Power Production Expenses	14,483,245	16,428,224	13.43%

	Account Number & Title		Last Year	This Year	% Change
1	**Transmission Expenses**				
2	Operation				
3	560	Operation Supervision & Engineering	9,029	9,734	7.80%
4	561	Load Dispatching	77,222	52,527	-31.98%
5	562	Station Expenses	47,128	61,501	30.50%
6	563	Overhead Line Expenses	23,590	24,866	5.41%
7	564	Underground Line Expenses	280	(586)	-309.69%
8	565	Transmission of Electricity by Others	1,044,802	672,591	-35.63%
9	566	Miscellaneous Transmission Expenses	14,823	11,295	-23.80%
10	567	Rents	10,062	15,177	50.83%
11					
12	TOTAL Operation - Transmission		1,226,937	847,105	-30.96%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	12,956	9,391	-27.51%
15	569	Maintenance of Structures	4,025	2,705	-32.80%
16	570	Maintenance of Station Equipment	44,142	78,661	78.20%
17	571	Maintenance of Overhead Lines	60,349	49,083	-18.67%
18	572	Maintenance of Underground Lines	21	546	2520.16%
19	573	Maintenance of Misc. Transmission Plant	20,291	9,455	-53.40%
20					
21	TOTAL Maintenance - Transmission		141,783	149,841	5.68%
22					
23	TOTAL Transmission Expenses		1,368,720	996,945	-27.16%
24					
25	**Distribution Expenses**				
26	Operation				
27	580	Operation Supervision & Engineering	33,309	44,095	32.38%
28	581	Load Dispatching	45,072	50,078	11.11%
29	582	Station Expenses	64,336	56,223	-12.61%
30	583	Overhead Line Expenses	160,664	204,818	27.48%
31	584	Underground Line Expenses	108,135	178,093	64.69%
32	585	Street Lighting & Signal System Expenses	11,332	3,971	-64.96%
33	586	Meter Expenses	87,123	66,372	-23.82%
34	587	Customer Installations Expenses	9,210	27,123	194.49%
35	588	Miscellaneous Distribution Expenses	149,626	246,334	64.63%
36	589	Rents	15,845	23,857	50.56%
37					
38	TOTAL Operation - Distribution		684,654	900,964	31.59%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	41,361	52,591	27.15%
41	591	Maintenance of Structures	1,387	241	-82.60%
42	592	Maintenance of Station Equipment	24,559	85,089	246.47%
43	593	Maintenance of Overhead Lines	462,673	662,315	43.15%
44	594	Maintenance of Underground Lines	83,063	126,372	52.14%
45	595	Maintenance of Line Transformers	39,488	60,846	54.09%
46	596	Maintenance of Street Lighting, Signal Sys	12,962	11,348	-12.45%
47	597	Maintenance of Meters	27,403	26,555	-3.10%
48	598	Maintenance of Miscellaneous Dist. Plant	13,906	20,992	50.95%
49					
50	TOTAL Maintenance - Distribution		706,802	1,046,349	48.04%
51					
52	TOTAL Distribution Expenses		1,391,456	1,947,313	39.95%
53					

	Account Number & Title	Last Year	This Year	% Change
1				
2	Customer Accounts Expenses			
3	Operation			
4	901 Supervision	64,167	75,654	17.90%
5	902 Meter Reading Expenses	241,259	269,571	11.74%
6	903 Customer Records & Collection Expenses	625,991	664,394	6.13%
7	904 Uncollectible Accounts Expenses	139,439	58,279	-58.21%
8	905 Miscellaneous Customer Accounts Expens	18,387	22,264	21.09%
9				
10	TOTAL Customer Accounts Expenses	1,089,243	1,090,162	0.08%
11				
12	Customer Service & Information Expenses			
13	Operation			
14	907 Supervision	5,315	7,657	44.07%
15	908 Customer Assistance Expenses	105,008	122,424	16.59%
16	909 Informational & Instructional Adv. Expense	11,464	31,508	174.85%
17	910 Miscellaneous Customer Service & Info. Ex	9,911	13,009	31.26%
18				
19	TOTAL Customer Service & Info Expenses	131,697	174,598	32.58%
20				
21	Sales Expenses			
22	Operation			
23	911 Supervision	9,683	9,489	-2.00%
24	912 Demonstrating & Selling Expenses	102,083	236,832	132.00%
25	913 Advertising Expenses	24,494	15,054	-38.54%
26	916 Miscellaneous Sales Expenses	22,371	13,807	-38.28%
27				
28	TOTAL Sales Expenses	158,631	275,182	73.47%
29				
30	Administrative & General Expenses			
31	Operation			
32	920 Administrative & General Salaries	1,269,133	1,436,357	13.18%
33	921 Office Supplies & Expenses	469,110	435,116	-7.25%
34	922 (Less) Administrative Expenses Transferred -	0	0	
35	923 Outside Services Employed	174,069	139,663	-19.77%
36	924 Property Insurance	157,042	149,408	-4.86%
37	925 Injuries & Damages	148,383	177,783	19.81%
38	926 Employee Pensions & Benefits	1,550,280	2,247,682	44.99%
39	927 Franchise Requirements	227	317	39.64%
40	928 Regulatory Commission Expenses	135,324	158,251	16.94%
41	929 (Less) Duplicate Charges - Cr.	(1,653,712)	(2,461,270)	48.83%
42	930.1 General Advertising Expenses	3,181	4,279	
43	930.2 Miscellaneous General Expenses	291,162	237,545	-18.41%
44	931 Rents	123,708	122,908	-0.65%
45				
46	TOTAL Operation - Admin. & General	2,667,907	2,648,038	-0.74%
47	Maintenance			
48	935 Maintenance of General Plant	64,794	87,273	34.69%
49				
50	TOTAL Administrative & General Expenses	2,732,701	2,735,311	0.10%
51				
52	TOTAL Operation & Maintenance Expenses	22,383,262	23,647,735	5.65%
53				

Sch. 12 **MONTANA TAXES OTHER THAN INCOME**

	Description of Tax	Last Year	This Year	% Change
1	Property (Ad Valorem)	1,296,344	1,395,855	7.68%
3	Franchise and Occupation	1,925	(456)	-123.69%
5	Federal - Excise Superfund	9,275	8,786	-5.27%
7	Washington - Operating Revenue Fee		107,312	100.00%
9	Washington - Pollution Control Credit *	(20,022)	(19,690)	-1.66%
11	Montana - Energy Proceeds	3,891	3,232	-16.94%
13	Montana - Consumer Counsel	21,655	13,255	-38.79%
15	Montana - Regulatory Commission	72,969	0	-100.00%
17	Other - Miscellaneous Taxes & License	952	354	-62.82%
53	TOTAL MT Taxes other than Income	1,386,989	1,508,648	8.77%

Sch. 13 PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	International Line Builders, Inc.	Const./Maint. Contracts	13,928,369.62	238,356.19	1.7113%
2	Stoel Rives Boley Jones	Legal	12,890,145.21	220,589.05	1.7113%
3	General Electric Company	Const./Maint. Contracts	11,138,786.66	190,618.06	1.7113%
4	Hawkeye Construction	Const./Maint. Contracts	11,126,424.14	190,406.50	1.7113%
5	B L Montague Co, Inc	Const./Maint. Contracts	10,025,850.28	171,572.38	1.7113%
6	L E Myers Company	Const./Maint. Contracts	9,864,800.86	168,816.34	1.7113%
7	Job Line Construction	Const./Maint. Contracts	8,773,683.51	150,144.05	1.7113%
8	Plant Maintenance Services, Inc.	Const./Maint. Contracts	7,114,013.61	121,742.11	1.7113%
9	Trees, Inc.	Tree Trimming	6,899,165.79	118,065.42	1.7113%
10	James River Corporation	Const./Maint. Contracts	6,496,606.08	111,176.42	1.7113%
11	Oracle Corporation	Other Consultants	6,403,182.91	109,577.67	1.7113%
12	Ames Construction, Inc.	Const./Maint. Contracts	5,575,063.84	95,406.07	1.7113%
13	Bonneville Power Adminisration	Const./Maint. Contracts	5,330,141.00	91,214.70	1.7113%
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26	Total		115,566,233.51	1,977,684.96	
27					
28	Costs assignable directly to Montana:				
29	Harp Line Constructors Company	Const./Maint. Contracts	1,929,864.87	1,929,864.87	100%
30	Trees, Inc.	Tree Trimming	266,294.12	266,294.12	100%
31					
32					
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52					
53	Total		2,196,158.99	2,196,158.99	

Sch. 14	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS		
Description	Total Company	Montana (1)	% Montana
Legislature Expense	**$499,193**	**0**	**0.00%**
Westerberg / Panter - legal fees in association with legislature activities	**78,861**	**0**	**0.00%**
Other Expenditures	**482,082**	**0**	**0.00%**
(1) PAC contributions are charged to account 426.4 and are not allocated to Montana for rate making purposes.			
TOTAL (1)	**1,060,136**	**0**	**0.[illegible]%**

Sch. 15 PENSION COSTS

	Description	Last Year	This Year	% Change
1				
2	Defined Benefit Plan?	yes	yes	
3				
4	Defined Contribution Plan?	yes	yes	
5				
6	Actuarial Cost Method	Projected Unit	Projected Unit	
7		Credit Method	Credit Method	
8	Is the Plan overfunded?	no	no	
9				
10	Accumulated Benefit Obligation	555,673,703	666,896,618	20.02%
11	Projected Benefit Obligation	626,822,646	756,485,834	20.69%
12	Fair Value of Plan Assets	473,284,874	495,455,058	4.68%
13				
14	Discount Rate for Benefit Obligations	9.00%	8.50%	-5.56%
15	Expected Long-Term Return on Assets	9.00%	8.75%	-2.78%
16				
17	Net Periodic Pension Cost:			
18	Service Cost	13,063,687	15,007,334	14.88%
19	Interest Cost	52,641,877	60,212,945	14.38%
20	Return on Plan Assets	(40,974,592)	(40,437,237)	-1.31%
21	Amortization of Transition Amount	4,193,431	7,905,862	88.53%
22	Amortization of Gains or Losses	(2,157,071)	0	
23	Total Net Periodic Pension Cost	26,767,332	42,688,904	59.48%
24				
25	Minimum Required Contribution	9,197,298	25,926,550	181.89%
26	Actual Contribution	26,767,000	43,538,410	62.66%
27	Maximum Amount Deductible	60,692,363	122,198,535	101.34%
28	Benefit Payments	45,950,376	47,803,320	4.03%
29				
30	Montana Intrastate Costs:			
31	Pension Costs	310,868	505,676	62.67%
32	Pension Costs Capitalized	129,642	224,859	73.45%
33	Accumulated Pension Asset (Liability) at Year End	(2,605,228)	(2,647,916)	1.64%
34				
35	Number of Company Employees:			
36	Covered by the Plan	12,498	13,479	7.85%
37	Not Covered by the Plan	N/A	N/A	
38	Active	8,048	8,696	8.05%
39	Retired	3,539	3,723	5.20%

Sch 16 OTHER POST EMPLOYMENT BENEFITS (OPEBS)

	Description	Last Year	This Year	% Change
1	General Information			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	9.00%	8.50%	-5.56%
5	Expected Long-Term Return on Assets	0.00%	8.50%	
6	Medical Cost Inflation Rate	12% to 6%	13% to 5%	
7	Actuarial Cost Method	Projected Unit	Projected Unit	
8		Credit Method	Credit Method	
9	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
10	Method - Tax Advantaged (Yes or No)			
11	VEBA			
12	401(h)			
13				
14				
15				
16	Describe Changes to the Benefit Plan:			
17				
18				
19				
20	Total Company			
21				
22	Accumulated Post Retirement Benefit Obligation (APBO)	234,281,000	280,253,947	19.62%
23	Fair Value of Plan Assets	0	30,716,000	
24	List the amount funded through each funding method:			
25	VEBA		23,716,000	
26	401(h)		7,000,000	
27	Other ____________			
28	Total amount funded	0	30,716,000	
29				
30	List amount that was tax deductible for each type of funding:			
31	VEBA		23,716,000	
32	401(h)		7,000,000	
33	Other ____________			
34	Total amount that was tax deductible	0	30,716,000	
35				
36	Net Periodic Post Retirement Benefit Cost:			
37	Service Cost	4,759,000	5,835,975	22.63%
38	Interest Cost	20,947,000	23,780,037	13.52%
39	Return on Plan Assets	0	0	
40	Amortization of Transition Obligation	11,714,000	14,012,697	19.62%
41	Amortization of Gains or Losses	0	0	
42	Total Net Periodic Post Retirement Benefit Cost	37,420,000	43,628,709	16.59%
43				
44	Benefit Cost Expensed	26,407,294	30,199,792	14.36%
45	Benefit Cost Capitalized	11,012,706	13,428,917	21.94%
46	Benefit Payments	12,600,000	12,912,885	2.48%
47				
48	Number of Company Employees:			
49	Covered by the Plan	11,704	12,741	8.86%
50	Not Covered by the Plan	N/A	N/A	
51	Active	8,604	9,487	10.26%
52	Retired	3,100	3,254	4.97%
53	Spouse/Dependants covered by the Plan	N/A	N/A	

	Description	Last Year	This Year	% Change
1				
2	Montana			
3				
4	Accumulated Post Retirement Benefit Obligation (APBO)	3,855,562	4,795,986	24.39%
5	Fair Value of Plan Assets	0	525,643	
6	List the amount funded through each funding method:			
7	VEBA		405,852	
8	401(h)		119,791	
9	Other ___________			
10	Total amount funded	0	525,643	
11				
12	List amount that was tax deductible for each type of funding:			
13	VEBA		405,852	
14	401(h)		119,791	
15	Other ___________			
16	Total amount that was tax deductible	0	525,643	
17				
18	Net Periodic Post Retirement Benefit Cost:			
19	Service Cost	78,319	99,871	27.52%
20	Interest Cost	344,725	406,948	18.05%
21	Return on Plan Assets	0	0	
22	Amortization of Transition Obligation	192,777	239,799	24.39%
23	Amortization of Gains or Losses	0	0	
24	Total Net Periodic Post Retirement Benefit Cost	615,821	746,618	21.24%
25				
26	Benefit Cost Expensed	434,585	516,809	18.92%
27	Benefit Cost Capitalized	181,236	229,809	26.80%
28	Benefit Payments	207,358	220,978	6.57%
29				
30	Number of Company Employees:			
31	Covered by the Plan	N/A	N/A	
32	Not Covered by the Plan	N/A	N/A	
33	Active	N/A	N/A	
34	Retired	N/A	N/A	
35	Spouse/Dependants covered by the Plan	N/A	N/A	
36				
37	Regulatory Treatment			
38				
39	Commission authorized - most recent			
40	Docket number:			
41	Order number:			
42				
43	Amount recovered through rates	N/A	0	

Sch. 17 TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

	Name/Title	Base Salary	Bonuses	Other	Total
1	Area Manager B	73,194	0	11,681	84,875
	Detail of "Other"				
	- Excess Life Insurance			766	
	- Vehicle Allowance			8,100	
	- Personal Time Sold			2,590	
	- Safety Award			225	
2	Area Operations Manager B	63,666	1,249	17,346	82,261
	Detail of "Other"				
	- Excess Life Insurance			823	
	- Relocation Bonus			14,556	
	- Personal Time Sold			1,842	
	- Safety Award			125	
3	District Manager B	68,428	1,467	11,136	81,031
	Detail of "Other"				
	- Excess Life Insurance			660	
	- Vehicle Allowance			8,100	
	- Personal Time Sold			2,226	
	- Safety Award			150	
4	Power Superintendent B	55,200	1,118	17,589	73,908
	Detail of "Other"				
	- Excess Life Insurance			507	
	- Relocation Bonus			15,230	
	- Personal Time Sold			1,702	
	- Safety Award			150	
5	District Manager B	63,810	1,346	8,180	73,336
	Detail of "Other"				
	- Vehicle Allowance			8,100	
	- Safety Award			80	
6	Area Customer Service Mgr B District Operations Manager	65,226	1,400	3,980	70,606
	Detail of "Other"				
	- Excess Life Insurance			1,778	
	- Personal Time Sold			2,152	
	- Safety Award			50	
7	Line Foreman/District	62,781	1,238	3,628	67,646
	Detail of "Other"				
	- Excess Life Insurance			3,346	
	- Premium Pay			107	
	- Safety Award			175	
8	Line Foreman/District	63,711	1,219	1,954	66,883
	Detail of "Other"				
	- Excess Life Insurance			719	
	- Premium Pay			1,134	
	- Safety Award			100	
9	Lineman/Journyman	59,016	1,192	3,257	63,466
	Detail of "Other"				
	- Excess Life Insurance			365	
	- Premium Pay			2,822	
	- Safety Award			70	
10	Lineman/Journyman	59,833	1,239	2,281	63,353
	Detail of "Other"				
	- Excess Life Insurance			304	
	- Premium Pay			1,851	
	- Safety Award			125	

Sch. 18 BALANCE SHEET

		Account Title	Last Year	This Year	% Change
1		Assets and Other Debits			
2	Utility Plant				
3	101	Electric Plant in Service	8,399,047,917	9,608,767,138	14 %
4	101.1	Property Under Capital Leases	18,958,044	21,615,657	14 %
5	102	Electric Plant Purchased or Sold	710,328,780	2,298,781	(100) %
6	103	Experimental Electric Plant Unclassified	1,286,190	1,286,190	
7	104	Electric Plant Leased to Others			
8	105	Electric Plant Held for Future Use	6,709,964	5,925,619	(12) %
9	106	Completed Constr. Not Classified - Electric	43,032,492	47,392,504	10 %
10	107	Construction Work in Progress - Electric	268,277,915	333,114,068	24 %
11	108	(Less) Accumulated Depreciation	2,630,596,417	2,975,274,684	13 %
12	111	(Less) Accumulated Amortization	53,971,709	64,212,576	19 %
13	114	Electric Plant Acquisition Adjustments	14,399,618	149,246,715	936 %
14	115	(Less) Accum. Amort. Elec. Acq. Adj.			
15	118-119	Other Utility Plant - Net	1,206,344	1,201,691	
16	120	Nuclear Fuel (Net)	80,360		(100) %
17		TOTAL Utility Plant	6,778,759,498	7,131,361,103	5 %
18					
19	Other Property & Investments				
20	121	Nonutility Property	7,693,205	7,635,264	(1) %
21	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.	1,003,415	968,911	(3) %
22	123	Investments in Associated Companies	6,107,928	6,107,928	
23	123.1	Investments in Subsidiary Companies	784,660,938	862,936,897	10 %
24	124	Other Investments	18,632,235	30,882,035	66 %
25	125	Sinking Funds			
26	128	Other Special Funds	77,550,142	10,629,518	(86) %
27		TOTAL Other Property & Investments	893,641,033	917,222,731	3 %
28					
29	Current & Accrued Assets				
30	131	Cash	(40,297,075)	(42,449,363)	5 %
31	132-134	Special Deposits	867,664	1,186,514	37 %
32	135	Working Funds	1,405,679	2,216,941	58 %
33	136	Temporary Cash Investments	25,600,000		(100) %
34	141	Notes Receivable	1,256,047	1,038,718	(17) %
35	142	Customer Accounts Receivable	181,449,297	205,900,565	13 %
36	143	Other Accounts Receivable	70,203,331	25,979,866	(63) %
37	144	(Less) Accum. Provision for Uncollectible Accts.	9,495,204	7,835,792	(17) %
38	145	Notes Receivable - Associated Companies	490,262	431,103	(12) %
39	146	Accounts Receivable - Associated Companies	2,058,124	3,547,639	72 %
40	151	Fuel Stock	70,018,817	59,554,619	(15) %
41	152	Fuel Stock Expenses Undistributed			
42	153	Residuals			
43	154	Plant Materials and Operating Supplies	120,064,866	112,462,352	(6) %
44	155	Merchandise	104,493	65,441	(37) %
45	156	Other Material & Supplies			
46	157	Nuclear Materials Held for Sale			
47	163	Stores Expense Undistributed	5,289,480	8,354,622	58 %
48	165	Prepayments	41,884,241	42,531,742	2 %
49	171	Interest & Dividends Receivable	1,546,037	1,426,792	(8) %
50	172	Rents Receivable	37,150	58,513	58 %
51	173	Accrued Utility Revenues	107,454,859	100,642,296	(6) %
52	174	Miscellaneous Current & Accrued Assets	26,777,559		(100) %
53		TOTAL Current & Accrued Assets	606,715,627	515,112,568	(15) %

Line		Account Title	Last Year	This Year	% Change
1		Assets and Other Debits (cont.)			
2					
3	Deferred Debits				
4					
5	181	Unamortized Debt Expense	15,216,218	20,145,318	32 %
6	182.1	Extraordinary Property Losses	3,899,777	2,835,389	(27) %
7	182.2	Unrecovered Plant & Regulatory Study Costs	29,936,179	29,351,127	(2) %
8	182.3	Regulatory Assets		1,034,356,182	
9	183	Prelim. Survey & Investigation Charges	4,517,077	4,062,094	(10) %
10	184	Clearing Accounts			
11	185	Temporary Facilities	233,543	143,952	(38) %
12	186	Miscellaneous Deferred Debits	262,070,721	81,243,918	(69) %
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	70,376,742	87,243,718	24 %
16	190	Accumulated Deferred Income Taxes	42,522,941	48,293,187	14 %
17		TOTAL Deferred Debits	428,773,198	1,307,674,885	205 %
18					
19		TOTAL Assets & Other Debits	8,707,889,356	9,871,371,287	13 %

Line		Account Title	Last Year	This Year	% Change
20					
21		Liabilities and Other Credits			
22					
23	Proprietary Capital				
24	201	Common Stock Issued	2,817,115,745	3,020,025,737	7 %
25	202	Common Stock Subscribed			
26	204	Preferred Stock Issued	636,360,450	586,360,450	(8) %
27	205	Preferred Stock Subscribed			
28	207	Premium on Capital Stock			
29	211	Miscellaneous Paid-In Capital			
30	212	Installments Received on Capital Stock	201,951	216,601	7 %
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	40,943,989	44,262,887	8 %
33	215	Appropriated Retained Earnings	3,182,660	3,193,230	
34	216	Unappropriated Retained Earnings	197,549,488	337,960,610	71 %
35	217	(Less) Reacquired Capital Stock	280,000	1,573,094	462 %
36		TOTAL Proprietary Capital	3,613,186,305	3,901,920,647	8 %
37					
38	Long Term Debt				
39					
40	221	Bonds	3,017,508,509	3,168,621,121	5 %
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies			
43	224	Other Long Term Debt			
44	225	Unamortized Premium on Long Term Debt	14,392,297	12,472,572	(13) %
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	3,408,263	2,396,296	(30) %
46		TOTAL Long Term Debt	3,028,492,543	3,178,697,397	5 %

Line	Acct.	Account Title	Last Year	This Year	% Change
1					
2		Total Liabilities and Other Credits (cont.)			
3					
4	Other Noncurrent Liabilities				
5					
6	227	Obligations Under Cap. Leases - Noncurrent	17,971,653	20,093,876	12 %
7	228.1	Accumulated Provision for Property Insurance	3,980,294	4,480,334	13 %
8	228.2	Accumulated Provision for Injuries & Damages	3,680,440	4,895,046	33 %
9	228.3	Accum. Provision for Pensions & Benefits		154,731,230	
10	228.4	Accumulated Misc. Operating Provisions	151,506,464	14,282,141	(91) %
11	229	Accumulated Provision for Rate Refunds	1,700,000		(100) %
12		TOTAL Other Noncurrent Liabilities	178,838,851	198,482,627	11 %
13					
14	Current & Accrued Liabilities				
15					
16	231	Notes Payable	362,622,634	263,613,866	(27) %
17	232	Accounts Payable	201,375,063	217,607,057	8 %
18	233	Notes Payable to Associated Companies	19,176,263	16,722,405	(13) %
19	234	Accounts Payable to Associated Companies	10,437,670	6,158,793	(41) %
20	235	Customer Deposits	8,612,086	8,727,962	1 %
21	236	Taxes Accrued	61,047,317	49,629,911	(19) %
22	237	Interest Accrued	78,597,727	81,337,520	3 %
23	238	Dividends Declared	114,201,141	85,840,213	(25) %
24	239	Matured Long Term Debt	15,450	133,325	763 %
25	240	Matured Interest	72,214	91,135	26 %
26	241	Tax Collections Payable	7,075,057	6,628,999	(6) %
27	242	Miscellaneous Current & Accrued Liabilities	80,605,066	44,103,487	(45) %
28	243	Obligations Under Capital Leases - Current	275,339	1,521,781	453 %
29		TOTAL Current & Accrued Liabilities	944,113,027	782,116,454	(17) %
30					
31	Deferred Credits				
32					
33	252	Customer Advances for Construction	13,917,753	12,884,234	(7) %
34	253	Other Deferred Credits	89,293,912	87,415,082	(2) %
35	254	Regulatory Liabilities		77,393,077	
36	255	Accumulated Deferred Investment Tax Credit	191,597,943	181,666,252	(5) %
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt	4,824,417	4,022,035	(17) %
39	281-283	Accumulated Deferred Income Taxes	643,624,605	1,446,773,482	125 %
40		TOTAL Deferred Credits	943,258,630	1,810,154,162	92 %
41					
42		TOTAL Liabilities & Other Credits	8,707,889,356	9,871,371,287	13

Name of Respondent PacifiCorp	This Report is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1993

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be attached hereto.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PacifiCorp (the "Company") is an electric utility that conducts its retail electric utility business through two divisions, Pacific Power & Light Company ("Pacific Power") and Utah Power & Light Company ("Utah Power"), and engages in power production and sales on a wholesale basis under the name PacifiCorp. The Company holds investments, through its wholly-owned subsidiary PacifiCorp Holdings, Inc. ("Holdings"), in subsidiaries including a telecommunications company (Pacific Telecom, Inc.), and a financial services company (PacifiCorp Financial Services, Inc.).

In June 1993, Holdings sold by merger its 82 percent-owned mining and resource development subsidiary (NERCO, Inc.). In September 1993, Pacific Telecom, Inc. ("Pacific Telecom") closed the sale of its interest in an international communications business (TRT Communications, Inc.). See Note 13.

These regulatory basis financial statements have been prepared for the purpose of complying with, and on the basis of accounting practices specified by the Federal Energy Regulatory Commission ("FERC"). Accordingly, investments in subsidiaries are accounted for and reported on the equity basis of accounting and these regulatory basis financial statements do not include debt of the Leveraged ESOP Trust established under the PacifiCorp K Plus Employee Savings and Stock Ownership Plan ("K Plus Plan") which is guaranteed by Holdings and do not present financial position, results of operations and changes in cash flows in accordance with generally accepted accounting principles, which would require that the accounts of the subsidiaries be consolidated with those of PacifiCorp.

The Company and Holdings guarantee certain debt of the Leveraged ESOP Trust established under the K Plus Plan (the "Trust"). The amounts guaranteed at December 31, 1993 were $16,736,000 and $25,398,000 for the Company and Holdings, respectively. In addition, the Company and Holdings guarantee the Trust's performance under certain interest rate swaps having a total notional principal amount of $24,000,000 that were entered into by the Trust and a commercial bank. These arrangements change the interest rate exposure on the variable rate debt guaranteed by the Company and Holdings to effective rates of 7 percent and 6.9 percent, respectively, at December 31, 1993. The debt was used to acquire the Company's common stock. Remaining unallocated common shares held in trust total 1,921,287.

If generally accepted accounting principles were followed, current assets (in thousands of dollars) would have been increased by $439,607 and $299,883; property, plant and equipment would have been increased by $1,078,255 and $1,078,899; current liabilities would have been increased by $661,136 and $508,966; long-term debt would have been increased by $744,910 and $818,002; deferred credits would have been increased by $828,803 and $667,533. Furthermore, operating revenues would have been increased by $905,504 and $879,589; operating expenses would have been increased by $585,467 and $753,255 for the years ended December 31, 1993 and 1992, respectively. Net cash provided by operating activities would have been increased by $315,008 and net cash used by investing activities would have been decreased by $286,378 for the year ended December 31, 1993. The accounting for investments in subsidiaries on the equity method rather than in accordance with generally accepted accounting principles has no effect on net income; however, on a consolidated basis, common shareholder capital would have been decreased by $21,156 and $21,156 and retained earnings would have been increased by $10,185 and $9,643 as of December 31, 1993 and 1992, respectively, due to Holding's purchase of common stock of the Company and subsequent dividend declarations. See Note 4.

NOTES TO FINANCIAL STATEMENTS (Continued)

Regulatory Authorities

Accounting for the Company conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by FERC and the regulatory commissions of the various states in which the Company operates.

Cash and Cash Equivalents

For the purposes of these financial statements, the Company considers all liquid investments with original maturities of three months or less to be cash equivalents.

Electric Property, Plant and Equipment

Electric property, plant and equipment are stated at original cost of contracted services, direct labor and material, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable utility properties retired, including the cost of removal, less salvage, is charged to accumulated depreciation. Maintenance and repairs of property and replacement and renewals of items that are not units of property are charged to operating expense.

Depreciation and Amortization

Depreciation and amortization are computed generally by the straight-line method over the estimated useful lives of the related assets. Provisions for depreciation of electric plant (excluding amortization of capital leases) was 2.9 percent and 3.2 percent of average depreciable assets in 1993 and 1992, respectively.

In 1993, based on a study by an independent consultant, the Company extended the lives of its thermal generating plants, decreasing depreciation expense by $24 million and increasing net income by $16 million.

Inventory Valuation

Inventories are generally valued at the lower of average cost or market.

Regulatory Assets

The Company capitalizes certain costs in accordance with regulatory authority whereby those costs will be recovered in future periods. Regulatory assets-net at December 31 included the following: 1993 - deferred taxes-net $730,092,442; deferred pension costs, $128,483,626; and various other costs of $130,573,553; 1992 - deferred pension costs of $134,857,367 and various other costs, $103,929,060.

Interest Capitalized

Costs of debt and equity funds applicable to utility properties are capitalized during construction. Generally, the composite capitalization rate allowed was 5.1 percent for 1993 and 7.1 percent for 1992.

Income Taxes

Effective January 1, 1993, the Company adopted Statement of Financial Accounting Standards ("SFAS") 109, "Accounting for Income Taxes." This statement requires use of the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. The cumulative effect of adoption of SFAS 109 resulted in an increase in net income in 1993 of $2,096,000.

Investment tax credits are deferred and amortized to income over the average estimated lives of the properties.

Revenue Recognition

The Company accrues estimated unbilled revenues for electric services provided after cycle billing through month-end.

Reclassifications

Certain amounts from prior years have been reclassified to conform with the 1993 method of presentation. These reclassifications had no effect on previously reported net income.

NOTE 2. ACQUISITION

On April 15, 1992, the Company purchased 243 megawatts of generating assets and fuel resources from Colorado-Ute Electric Association, Inc. for $279,264,000. The purchase was financed with $250,338,000 of first mortgage and collateral trust bonds, including $47,540,000 issued as collateral for obligations assumed relating to pollution control revenue bonds.

Noncash investing and financing activities in 1992 associated with the acquisition were as follows:

	THOUSANDS OF DOLLARS 1992
Net assets acquired	$ (279,264)
Long-term debt assumed	250,338
Accrued liabilities and deferred credits assumed	4,845

NOTE 3. SHORT-TERM DEBT AND BORROWING ARRANGEMENTS

At December 31, 1993, the Company had outstanding $186,913,866 of commercial paper and $76,700,000 of borrowings under available bank lines backed by a $500 million revolving credit agreement. Commitment fees were approximately $946,178 in 1993 and $619,177 in 1992. Covenants in certain reimbursement agreements relating to letters of credit limit short-term borrowings to 12 percent of defined capitalization (limiting such borrowings to approximately $491,100,000 at December 31, 1993.)

NOTE 4. COMMON AND PREFERRED STOCK

At December 31, 1993 and 1992, the Company had authorized common stock of 750,000,000 shares. The Company had 281,020,717 and 270,579,042 outstanding common shares at December 31, 1993 and 1992, respectively.

Changes in shares of capital stock and common shareholder capital are listed below:

THOUSANDS OF SHARES/DOLLARS	SHARES COMMON STOCK	SHARES PREFERRED STOCK	COMMON SHAREHOLDER CAPITAL
BALANCE, JANUARY 1, 1992	262,411	4,843	$2,601,920
1992 Sales through Dividend Reinvestment and Stock Purchase Plan	3,790	-	81,551
Sales through Employees' Stock Plans	1,070	-	23,395
Sales to the public	3,308	5,750	74,661
Stock expense, redemptions and repurchases	-	(60)	(5,433)
BALANCE, DECEMBER 31, 1992	270,579	10,533	2,776,094
1993 Sales through Dividend Reinvestment and Stock Purchase Plan	2,947	-	56,185
Sales through Employees' Stock Plans	853	-	15,940
Sales to the public	6,642	-	130,810
Stock expense, redemptions and repurchases	-	(1)	(4,623)
BALANCE, DECEMBER 31, 1993	281,021	10,532	$2,974,406

At December 31, 1993, there were 15,035,454 authorized but unissued shares of common stock reserved for issuance under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings and

Stock Ownership Plans and for sales to the public. Eligible employees under the employee plans may direct their pretax elective contributions into the purchase of the Company's common stock. The Company makes matching contributions equal to a percentage of employee contributions, which are also invested in the Company's common stock. Employee contributions eligible for matching contributions are limited to 6 percent of compensation.

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon involuntary liquidation, all preferred stock is entitled to stated value or specified preference amount per share plus accrued dividends.

	THOUSANDS OF SHARES/DOLLARS PREFERRED STOCK OUTSTANDING AT DECEMBER 31			
SERIES	1993 SHARES	1993 AMOUNT	1992 SHARES	1992 AMOUNT
SUBJECT TO MANDATORY REDEMPTION:				
NO PAR SERIAL PREFERRED, 16,000 SHARES AUTHORIZED				
$7.12 ($100 stated value)	440	$ 44,000	440	$ 44,000
7.48	750	75,000	750	75,000
7.70	1,000	100,000	1,000	100,000
TOTAL SUBJECT TO MANDATORY REDEMPTION		$219,000		$219,000
NOT SUBJECT TO MANDATORY REDEMPTION:				
SERIAL PREFERRED $100 STATED VALUE PER SHARE, 3,500 SHARES AUTHORIZED				
4.52%	2	$ 207	2	$ 207
4.56%	85	8,459	85	8,459
4.72%	70	6,989	70	6,989
5.00%	42	4,200	42	4,200
5.40%	66	6,596	66	6,596
6.00%	6	593	6	593
7.00%	18	1,806	18	1,806
7.96%	135	13,518	135	13,518
8.92%	69	6,937	69	6,937
9.08%	165	16,489	165	16,489
NO PAR SERIAL PREFERRED, 16,000 SHARES AUTHORIZED				
$1.16 ($25 stated value)	193	4,828	193	4,828
$1.18	420	10,503	420	10,503
$1.28	381	9,530	381	9,530
$1.76	394	9,847	394	9,847
$1.98	502	12,550	502	12,550
$1.98, Series 1992	5,000	125,000	5,000	125,000
$2.13	666	16,655	666	16,655
Auction Rate ($100,000 stated value) (a)	1	100,000	2	150,000
5% PREFERRED, $100 STATED VALUE, 127 SHARES AUTHORIZED AND OUTSTANDING	127	12,653	127	12,653
TOTAL NOT SUBJECT TO MANDATORY REDEMPTION		$367,360		$417,360

(a) Dividend rates at December 31, 1993 on 500 shares of Series A and Series C were 3.45 percent and 3.46 percent, respectively.

The fair value, based upon bid prices from an investment bank, of the redeemable preferred stock is estimated to be $234,000,000, or 107 percent of the carrying value, and $218,000,000, or 99 percent of the carrying value, at December 31, 1993 and 1992, respectively.

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: beginning in 1997, 15,000 shares of the $7.12 series are redeemable annually; the $7.70 series is redeemable in its entirety on August 15, 2001; and 37,500 shares of the $7.48 series are redeemable on each June 15 from 2002 through 2006, with all shares outstanding on June 15, 2007 redeemable on that date. Mandatory redemption requirements for 1993 through 1996 on the $7.12 series were satisfied by the purchase of 60,000 shares at a discount in December 1992. If the Company is in default in its obligation to make any future redemptions on the $7.12 series or the $7.48 series, it may not pay cash dividends on common stock.

NOTE 5. LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

The Company's long-term debt and capital lease obligations were as follows:

THOUSANDS OF DOLLARS/DECEMBER 31,	1993	1992
FIRST MORTGAGE AND COLLATERAL TRUST BONDS		
Maturing 1994 through 1998 / 4.5% - 9.4% (a)	$ 651,179	$ 571,287
Maturing 1999 through 2003 / 5.9% - 10%	895,447	743,725
Maturing 2004 through 2008 / 6.8% - 7.9%	257,724	455,514
Maturing 2009 through 2013 / 7.3% - 9.2%	216,520	168,535
Maturing 2014 through 2018 / 8.3% - 8.7%	109,096	202,767
Maturing 2019 through 2023 / 6.7% - 8.5%	341,500	175,000
GUARANTY OF POLLUTION CONTROL REVENUE BONDS		
6% due 2003	21,260	21,260
5.6% - 10.7% due 1994 through 2023 (b)	270,970	272,880
Variable rate due 2005 through 2019 (c)	404,925	407,425
Funds held by trustees		(885)
OTHER		
Unamortized premium and (discount)	10,076	10,984
Capital lease obligations (Note 6)	21,616	18,247
TOTAL	3,200,313	3,046,739
Less current maturities	70,251	52,294
LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS	$3,130,062	$2,994,445

(a) Includes $50,000 of 9 3/8 percent bonds issued to secure obligations under an equivalent 10-year yen loan. A currency swap converted the fixed rate yen liability to a floating rate U.S. dollar liability based on six-month LIBOR plus .02 percent (interest rate 3.5 percent at December 31, 1993).

(b) Secured by pledged first mortgage and collateral trust bonds generally at the same interest rates, maturity dates and redemption provisions as the secured pollution control revenue bonds.

(c) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates or prime rates.

In accordance with SFAS 107, "Disclosures about Fair Value of Financial Instruments," the fair value of the Company's long-term debt at December 31, 1993 and 1992 has been estimated by discounting the projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities. The fair value of the Company's long-term debt, including current portion and excluding leveraged ESOP loan guarantees and capital lease obligations, is estimated to be (in thousands of dollars) $3,396,000, or 107 percent of the carrying value of $3,179,000 and $3,206,000, or 103 percent of the carrying value of $3,122,000 at December 31, 1993 and 1992, respectively.

The Company has entered into interest rate swap and exchange agreements to reduce the impact of changes in interest rates on its variable rate long-term debt. At December 31, 1993, the Company had five outstanding interest rate contracts with commercial banks and Fortune 500 companies, having a total notional principal amount of $187,000,000. These agreements effectively change the Company's interest rate exposure on the underlying variable rate debt to effective rates of 6.7 percent to 8.9 percent. These contracts mature at various times up to the year 2000. The Company is exposed to credit loss in the event of nonperformance by the other parties to the interest rate swap agreements. However, the Company does not anticipate nonperformance by the counterparties.

The fair value of interest rate swaps is the estimated amount that the Company would pay to terminate the swap agreements, taking into account current interest rates and the current credit worthiness of the swap counterparties. The estimated termination cost would have been (in thousands of dollars) $57,066 and $55,895 at December 31, 1993 and 1992, respectively.

Approximately $4.6 billion of the assets of the Company secure long-term debt and capital lease obligations. First mortgage and collateral trust bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Maturity and sinking fund requirements on all long-term debt and capital lease obligations and redeemable preferred stock outstanding are as follows:

THOUSANDS OF DOLLARS/FOR THE YEAR	1994	1995	1996	1997	1998
Total requirements	$71,813	$49,833	$181,956	$213,174	$220,382
Portion of total payable in cash	70,251	48,683	180,806	210,374	217,782
Property additions certifiable in lieu of cash (a)	2,375	1,438	750	750	417

(a) Certain cash sinking fund requirements may be satisfied on the basis generally of 60% of property additions.

The Company's Mortgages and Deeds of Trust, as supplemented, relating to its long-term debt, restrict the payment of cash dividends and other distributions on common stock. At December 31, 1993, the Company's retained earnings available for these purposes was $266 million.

The Company made interest payments, net of capitalized interest, of (in thousands of dollars) $254,583 and $256,736 in 1993 and 1992, respectively.

NOTE 6. LEASES

The Company leases certain properties under leases with various expiration dates and renewal options. Rentals on lease renewals are subject to negotiation. Certain leases provide for options to purchase at fair market value. The Company is also committed to pay all taxes, expenses of operation (other than depreciation) and maintenance applicable to the leased property.

Net rent expense for the years ending December 31, 1993 and 1992 was (in thousands of dollars) $13,564 and $14,890, respectively.

Future minimum lease payments under noncancelable operating leases are (in thousands of dollars) $5,054, $3,187, $2,038, $1,919 and $1,850 for 1994 through 1998, respectively.

NOTE 7. COMMITMENTS AND CONTINGENCIES

Construction and Other

Construction programs are estimated at $736 million for 1994. As part of these programs, substantial commitments have been made.

Several Superfund sites have been identified where the Company has been or may be designated as a potentially responsible party. Future costs associated with the disposition of these matters are not expected to be material to the Company's results of operation.

The Company is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management presently believes that disposition of these matters will not have a materially adverse effect on the Company's financial position or results of operations.

Jointly Owned and Leased Plant

At December 31, 1993, the Company's participation in jointly owned plants is as follows:

THOUSANDS OF DOLLARS	The Company's Share	Plant in Service	Accumulated Depreciation	Construction Work in Progress
JOINTLY OWNED PLANTS				
Centralia	47.5%	$175,595	$ 98,745	$ 5,611
Jim Bridger Units 1, 2, 3 and 4	66.7%	781,826	272,650	3,923
Trojan (a)	2.5%	-	-	-
Colstrip Units 3 and 4	10.0%	199,267	47,611	974
Hunter Unit 1	93.8%	252,130	85,520	598
Hunter Unit 2	60.3%	180,086	56,792	1,401
Wyodak	80.0%	289,386	86,313	20,225
Craig Station, Units 1 and 2	19.3%	144,079 (b)	47,319	2,891
Hayden Station, Unit 1	24.5%	14,961 (b)	11,538	578
Hayden Station, Unit 2	12.6%	16,437 (b)	7,472	393

(a) Plant, inventory, fuel and decommissioning costs totaling $29,105 relating to the Trojan Plant were included in regulatory assets-net at December 31, 1993. Recovery of these costs is pending approval of certain regulatory commissions.

(b) Excludes unallocated acquisition adjustments of $135,454.

Under the joint agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. The Company's portion is recorded in its applicable operations, maintenance and tax accounts.

Substantial amounts of power are purchased from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. The Company is required to pay its portion of the debt service, whether or not any power is produced. The arrangements provide for nonwithdrawable power and most of them also provide for additional power, withdrawable by the districts upon one to five years' notice. For 1993, such purchases approximated 2.9 percent of energy requirements; an additional 12.7 percent was obtained through other purchase and net interchange arrangements.

At December 31, 1993, the Company's share of long-term arrangements with public utility districts was as follows:

Generating Facility	Year Contract Expires	Capacity (kw)	Percentage of Output	Annual Costs (a) (in thousands)
Wanapum	2009	155,444	18.7%	$ 5,455
Priest Rapids	2005	109,602	13.9	3,777
Rocky Reach	2011	64,297	5.3	1,851
Wells	2018	54,198	7.0	1,867
TOTAL		383,541		$12,950

(a) Annual costs include debt service of $7,524.

The Company has a 4 percent interest in the Intermountain Power Project ("Project"), located in central Utah. The Company and the City of Los Angeles have agreed that the City will purchase capacity and energy from Company plants equal to the Company's 4 percent entitlement of the Project at a price equivalent to 4 percent of the expenses and debt service of the Project.

NOTE 8. INCOME TAXES

Excluding equity in subsidiaries earnings or losses, the Company's effective combined federal and state income tax rate was 33 percent and 39 percent in 1993 and 1992, respectively. The difference between taxes calculated as if the statutory federal tax rate of 35 percent in 1993 and 34 percent in 1992 was applied to income before income taxes and the recorded tax expense is reconciled as follows:

THOUSANDS OF DOLLARS/FOR THE YEAR	1993	1992
COMPUTED FEDERAL INCOME TAXES	$189,449	$ 137,566
REDUCTION IN TAX RESULTING FROM		
Deficiency of tax over book depreciation (flow-through basis)	(9,863)	(20,329)
Investment tax credit	9,938	9,440
Depletion	5,270	4,944
Other items capitalized and miscellaneous differences	17,603	(2,218)
Federal tax reductions (increases)	22,948	(8,163)
FEDERAL INCOME TAX	166,501	145,729
STATE INCOME TAX, NET OF FEDERAL INCOME TAX BENEFIT	12,836	11,953
TOTAL INCOME TAX EXPENSE	$179,337	$ 157,682

The provision for income taxes is summarized as follows:

	1993	1992
Federal	$106,053	$ 101,179
State	13,898	12,370
Total	119,951	113,549
DEFERRED INCOME TAXES		
Federal	63,538	49,785
State	5,780	3,817
Total	69,318	53,602
INVESTMENT TAX CREDITS	(9,932)	(9,469)
TOTAL INCOME TAX EXPENSE	$179,337	$ 157,682

The Company adopted SFAS 109, "Accounting for Income Taxes," effective January 1, 1993. This statement requires use of the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. The cumulative effect of adoption of SFAS 109 resulted in an increase in net income in 1993 of (in thousands of dollars) $2,096. Assets increased (in thousands of dollars) $639,000 and liabilities increased $639,000, reflecting deferred income tax liabilities and related regulatory assets recorded for cumulative income tax temporary differences which will be recovered through rates when the temporary differences reverse. The regulatory asset is primarily based upon differences between the book and tax basis of utility plant in service and the accumulated reserve for depreciation.

The tax effects of significant items comprising the Company's net deferred tax liability at December 31, 1993 are as follows:

	THOUSANDS OF DOLLARS
DEFERRED TAX LIABILITIES	
Property, plant and equipment	$ 668,388
Regulatory asset	807,486
DEFERRED TAX ASSETS	
Regulatory liability	(77,393)
NET DEFERRED TAX LIABILITY	$1,398,481

The Internal Revenue Service ("IRS") completed its examination of the Company's federal income tax returns for the years 1983 through 1986. The Company and the IRS have agreed to a settlement on all of the issues, except for certain issues relating to the Company's abandonment of its 10 percent interest in Washington Public Power Supply System Unit 3. The Company and the IRS continue to discuss the remaining unagreed issues.

During 1993, the IRS completed its examination of the Company's federal income tax returns for 1987 and 1988, and has proposed certain adjustments increasing taxes by (in thousands of dollars) $13,600. Conferences with the IRS are ongoing in 1994.

In the opinion of management, the outcome of the 1983 through 1988 federal income tax examinations will not have a material effect on the Company's consolidated financial position or results of operation.

The Company's 1989 and 1990 federal income tax returns are currently under examination by the IRS.

The Company made income tax payments, net of refunds, of (in thousands of dollars) $132,558 and $167,457 in 1993 and 1992, respectively.

NOTE 9. RETIREMENT PLANS

The Company has pension plans covering substantially all of its employees. Benefits under these plans are generally based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments, to reflect benefits estimated to be received from Social Security. Pension costs are funded annually by no more than the maximum amount of pension expense which can be deducted for federal income tax purposes. Unfunded prior service costs are amortized over the remaining service period of employees expected to receive benefits. At December 31, 1993, plan assets were primarily invested in common stocks, bonds and U.S. government obligations.

Net pension cost is summarized as follows for the years ended December 31, 1993 and 1992:

THOUSANDS OF DOLLARS	1993	1992
Service cost - benefits earned	$ 15,156	$ 12,466
Interest cost on projected benefit obligation	60,606	57,141
Actual gain on plan assets	(78,010)	(16,824)
Net amortization and deferral	45,638	(18,689)
Regulatory deferral (a)	3,411	(6,486)
NET PENSION COST	$ 46,801	$ 27,608

(a) The Company has received accounting orders from its primary and certain other regulatory authorities to defer the difference between pension cost as determined in accordance with SFAS 87 and 88 and that determined for funding purposes.

The funded status, net pension liability and significant assumptions are as follows at December 31, 1993 and 1992:

	THOUSANDS OF DOLLARS	
	1993	1992
Actuarial present value of benefit obligations:		
Vested benefit obligation	$ 715,327	$ 550,362
Accumulated benefit obligation	746,500	612,264
Projected benefit obligation	858,105	689,863
Plan assets at fair value	564,795	461,069
Projected benefit obligation in excess of plan assets	(293,310)	(228,794)
Unrecognized prior service costs	9,860	9,911
Unrecognized net (gain) loss	20,082	(77,288)
Unrecognized net obligation at January 1, being amortized over 8 to 16 years	107,900	115,044
Minimum liability adjustment	(26,237)	(26,778)
NET PENSION LIABILITY	$(181,705)	$(207,905)
Discount rate	7.5%	9%
Expected long-term rate of return on assets	8.75%	9%
Rate of increase in compensation levels	6%	6%

The Company offered early retirement incentive programs in 1987 and 1990. Included in the table above is the present value of all future termination benefits provided of (in thousands of dollars) $68,000. The Company has received regulatory accounting orders to defer these costs as a regulatory asset to be amortized over 20 and 30 years.

NOTE 10. OTHER POSTRETIREMENT BENEFITS

The Company provides health care and life insurance benefits for eligible retirees on a basis substantially similar to those who are active employees. Effective January 1, 1993, the company adopted SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." The cost of postretirement benefits are now accrued over the active service period of employees. In 1992, the (in thousands of dollars) $9,959 cost of these benefits was charged to operating expenses as claims and premiums were paid. The transition obligation, which represents the previously unrecognized prior service cost, was (in thousands of dollars) $280,254 at January 1, 1993, and is being amortized over a period of 20 years. For those employees already retired at January 1, 1993, the Company will continue to fund postretirement benefit expense on a pay-as-you-go basis. For those employees retiring after January 1, 1993, the Company will fund postretirement benefit expense through a combination of funding vehicles. The Company funded (in thousands of dollars) $30,716 of postretirement benefit expense during 1993. These funds are invested in bonds and common stock.

The net periodic postretirement benefit cost at December 31, 1993 is summarized as follows:

	THOUSANDS OF DOLLARS
Service costs - benefits earned	$ 5,765
Interest cost on accumulated postretirement benefit obligation	23,754
Amortization of transition obligation	13,998
Regulatory deferral	(5,607)
NET PERIODIC POSTRETIREMENT BENEFIT COST	$ 37,910

The accumulated postretirement benefit obligation ("APBO") at December 31, 1993 was as follows:

	THOUSANDS OF DOLLARS
Retirees and dependents	$ 216,400
Fully eligible active plan participants	9,800
Other active plan participants	105,000
APBO	331,200
Plan assets at fair value	30,716
APBO in excess of plan assets	300,484
Unrecognized transition obligation	(266,241)
Unrecognized net loss	(34,355)
ACCRUED (PREPAID) POSTRETIREMENT BENEFIT OBLIGATION	$ (112)

The weighted average discount rate used in determining the accumulated postretirement benefit obligation was 7.5 percent. The assumed health care cost trend rates for participants under age 65 was 12 percent, with gradual decreases to 5 percent over 11 years and 4.5 percent thereafter. The assumed health care cost trend rate for participants over age 65 was 10 percent, with gradual decreases to 5 percent over 11 years and 4.5 percent thereafter. The health care cost trend rate assumptions have a significant effect on the amounts reported. Increasing the assumed health care cost trend rate by one percentage point would have increased the APBO as of December 31, 1993 by (in thousands of dollars) $22,565 and the annual net periodic postretirement benefit cost by $2,392.

NOTE 11. RELATED PARTY TRANSACTIONS

The Company and its subsidiaries participate in a consolidated cash management program. Any funds advanced to/from the Company are included in notes payable/receivable-affiliates. These notes are due upon demand and bear interest at a short-term rate as defined under intercompany loan agreements between the Company and its subsidiaries. Net interest expense on these advances was (in thousands of dollars) $931 and $195 in 1993 and 1992, respectively.

The Company provides certain management services, such as corporate and financial advice and consultation, to subsidiaries at cost. The amounts charged to the subsidiaries were (in thousands of dollars) $2,106 and $2,508 in 1993 and 1992, respectively.

During 1990 and 1989, Holdings purchased shares of the Company's common stock which were used in acquisitions of companies providing communications services in the Midwest by Pacific Telecom. Pacific Telecom provided the funding for the purchase of these shares. The shares not used in the acquisitions were sold by Holdings in 1992 to the K Plus Plan Trust and to the Company for use as awards in the PacifiCorp Long-Term Incentive Plan. Dividends paid to Holdings on these shares were (in thousands of dollars) $150 in 1992.

All of the coal production of the Bridger mine ("Bridger") is sold to a steam electric generating plant owned by the Company and Idaho Power Company ("Idaho"). Sales to the plant were (in thousands of dollars) $129,200 in 1993 and $124,700 in 1992. The Company provided Bridger with management, administrative, engineering services and electricity on an as-need basis. The amount charged for these services was (in thousands of dollars) $5,218 and $5,205 in 1993 and 1992, respectively. In addition, Bridger paid overriding royalties of (in thousands of dollars) $683 and $639 to the Company and Idaho in 1993 and 1992, respectively, pursuant to coal lease agreements.

NOTE 12. SUBSIDIARY SPECIAL CHARGES

As a result of credit rating downgrades in 1992, PacifiCorp Financial Services, Inc. ("Financial Services") and Holdings experienced restricted access to debt markets. In order to improve this situation, these subsidiaries attempted to reduce debt with cash generated by accelerating disinvestment of underperforming and nonstrategic assets. Related to this action, Financial Services and Holdings recorded various pretax adjustments of (in thousands of dollars) $141,755 and $43,940, respectively, to the carrying value of certain of their assets in the first quarter of 1992.

A summary of the special charges included in equity in subsidiary (earnings) losses is as follows:

	THOUSANDS OF DOLLARS
Holdings	$ 29,000
Financial Services	102,583
TOTAL	$ 131,583

NOTE 13. DISCONTINUED OPERATIONS OF SUBSIDIARIES

On February 18, 1993, Holdings announced an agreement to sell, by means of a merger, its 82 percent-owned mining and resource development business, NERCO, Inc. ("NERCO"), to a subsidiary of RTZ America, Inc. ("RTZ"). On June 2, 1993, Holdings completed the sale for cash consideration of $12 per NERCO share, or (in thousands of dollars) $384,000. In connection with this transaction, a subsidiary of Holdings loaned (in thousands of dollars) $225,000 at 13 percent interest to a subsidiary of RTZ, with repayment contingent upon future revenues received under a coal supply contract. The sale resulted in a gain to Holdings of approximately (in thousands of dollars) $183,000, including earnings through June 2, 1993, which has been deferred and is being recognized in earnings, using a modified installment method, as the loan is repaid. The loan could extend through 2009, but is prepayable without premium.

The discontinued operations of NERCO for the year ended December 31 are summarized as follows:

	THOUSANDS OF DOLLARS 1992
Revenues	$ 671,998
Costs and expenses	668,071
Losses on asset dispositions and write-downs	710,800
Loss from operations before income taxes	(706,873)
Income tax benefit	155,648
Minority interest and other	100,318
LOSS FROM DISCONTINUED OPERATIONS	$ (450,907)

A subsidiary of Pacific Telecom, International Communications Holdings, Inc. ("ICH"), closed the sale of its wholly owned subsidiary, TRT Communications, Inc. ("TRT"), to IDB Communications Group, Inc. ("IDB") on September 23, 1993. TRT had been shown as a discontinued operation, pending completion of agreement to sell. Pacific Telecom received 4,500,000 shares of IDB common stock and (in thousands of dollars) $1,000 in cash in exchange for the stock of TRT and the stock of another smaller subsidiary. Based on appreciation in the market value of the IDB common stock, Holdings recorded a (in thousands of dollars) $52,406 gain at closing in September 1993 on the transaction. The IDB common stock was registered and sold in a public offering in November 1993 and Pacific Telecom received $45 per share before commissions and expenses.

From the discontinued operations of ICH, Holdings incurred losses in 1992 of (in thousands of dollars) $39,703, which included $9,052 of operating losses and a $30,651 valuation adjustment. The valuation adjustment was based on the market value of the IDB common stock at the time the agreement was signed.

Sch. 19 **MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)**

Account Number & Title		Last Year	This Year	% Change
Intangible Plant				
301	Organization	460,690	441,908	-4.08%
302	Franchises & Consents	75,719	80,343	6.11%
303	Miscellaneous Intangible Plant	891,138	1,032,478	15.86%
TOTAL Intangible Plant		1,427,548	1,554,729	8.91%
Production Plant				
Steam Production				
310	Land & Land Rights	526,342	848,326	61.17%
311	Structures & Improvements	7,629,278	9,572,216	25.47%
312	Boiler Plant Equipment	27,844,978	35,059,293	25.91%
313	Engines & Engine Driven Generators	0	0	
314	Turbogenerator Units	6,771,399	8,390,414	23.91%
315	Accessory Electric Equipment	3,004,541	4,344,179	44.59%
316	Miscellaneous Power Plant Equipment	620,416	849,386	36.91%
TOTAL Steam Production Plant		46,396,954	59,063,813	27.30%
Nuclear Production				
320	Land & Land Rights	0	0	0.00%
321	Structures & Improvements	0	0	0.00%
322	Reactor Plant Equipment	0	0	0.00%
323	Turbogenerator Units	0	0	0.00%
324	Accessory Electric Equipment	0	0	0.00%
325	Miscellaneous Power Plant Equipment	0	0	0.00%
TOTAL Nuclear Production Plant		0	0	0.00%
Hydraulic Production				
330	Land & Land Rights	319,260	338,876	6.14%
331	Structures & Improvements	773,943	1,418,624	83.30%
332	Reservoirs, Dams & Waterways	4,988,148	5,396,854	8.19%
333	Water Wheels, Turbines & Generators	1,120,894	1,225,223	9.31%
334	Accessory Electric Equipment	380,223	438,021	15.20%
335	Miscellaneous Power Plant Equipment	89,633	99,264	10.74%
336	Roads, Railroads & Bridges	152,929	168,900	10.44%
TOTAL Hydraulic Production Plant		7,825,031	9,085,762	16.11%

	Account Number & Title	Last Year	This Year	% Change
	Production Plant (cont.)			
Other Production				
340	Land & Land Rights	0	0	0.00%
341	Structures & Improvements	0	0	0.00%
342	Fuel Holders, Producers & Accessorie	0	0	0.00%
343	Prime Movers	0	1,414	0.00%
344	Generators	0	2,406	0.00%
345	Accessory Electric Equipment	0	915	0.00%
346	Miscellaneous Power Plant Equipmen	0	0	0.00%
	TOTAL Other Production Plant	0	4,736	0.00%
	TOTAL Production Plant	54,221,985	68,154,311	25.69%
	Transmission Plant			
350	Land & Land Rights	691,796	859,716	24.27%
352	Structures & Improvements	345,570	380,520	10.11%
353	Station Equipment	7,539,360	9,068,364	20.28%
354	Towers & Fixtures	5,342,391	5,530,847	3.53%
355	Poles & Fixtures	3,123,138	3,839,423	22.93%
356	Overhead Conductors & Devices	7,455,473	8,625,210	15.69%
357	Underground Conduit	210	666	216.16%
358	Underground Conductors & Devices	304	534	75.82%
359	Roads & Trails	55,757	164,963	195.86%
	TOTAL Transmission Plant	24,554,000	28,470,242	15.95%
	Distribution Plant			
360	Land & Land Rights	217,526	217,746	0.10%
361	Structures & Improvements	415,636	389,173	-6.37%
362	Station Equipment	7,313,876	7,702,402	5.31%
363	Storage Battery Equipment	0	0	
364	Poles, Towers & Fixtures	7,923,870	8,815,829	11.26%
365	Overhead Conductors & Devices	8,273,699	9,277,590	12.13%
366	Underground Conduit	1,368,393	1,990,926	45.49%
367	Underground Conductors & Devices	2,190,422	2,745,134	25.32%
368	Line Transformers	12,181,076	13,406,009	10.06%
369	Services	4,439,634	4,671,298	5.22%
370	Meters	1,677,597	1,761,035	4.97%
371	Installations on Customers' Premises	170,135	168,096	-1.20%
372	Leased Property on Customers' Prem	0	0	
373	Street Lighting & Signal Systems	486,777	507,718	4.30%
	TOTAL Distribution Plant	46,658,641	51,652,956	10.70%

		Account Number & Title	Last Year	This Year	% Change
1					
2		General Plant			
3					
4	389	Land & Land Rights	20,032	20,797	3.82%
5	390	Structures & Improvements	1,421,966	1,787,851	25.73%
6	391	Office Furniture & Equipment	1,802,653	1,844,412	2.32%
7	392	Transportation Equipment	320,368	401,258	25.25%
8	393	Stores Equipment	82,390	80,305	-2.53%
9	394	Tools, Shop & Garage Equipment	431,248	471,046	9.23%
10	395	Laboratory Equipment	580,533	571,687	-1.52%
11	396	Power Operated Equipment	394,970	832,132	110.68%
12	397	Communication Equipment	857,438	1,097,406	27.99%
13	398	Miscellaneous Equipment	32,322	36,244	12.13%
14	399	Other Tangible Property	5,736,346	6,004,404	4.67%
15					
16		TOTAL General Plant	11,680,265	13,147,542	12.56%
17					
18		TOTAL (Account 101)	138,542,438	162,979,780	17.64%
19					
20	102	Communication Equipment	0	0	
21	103	Miscellaneous Equipment	35,771	37,955	6.11%
22	106	Other Tangible Property	10,944,030	2,793,652	-74.47%
23					
24		TOTAL Electric Plant in Service	149,522,239	165,811,387	10.89%

Sch. 20	MONTANA DEPRECIATION SUMMARY		Accumulated Depreciation		Current
	Functional Plant Classification	Plant Cost	Last Year Bal.	This Year Bal.	Avg. Rate
1					
2	Steam Production		16,815,708	21,776,603	2.45%
3	Nuclear Production		0	(2,711)	0.00%
4	Hydraulic Production		2,773,099	3,074,974	1.85%
5	Other Production		8,297	10,300	3.08%
6	Transmission		6,774,311	7,587,517	2.36%
7	Distribution		13,589,887	14,709,839	3.16%
8	General		3,996,616	4,477,775	5.83%
9	TOTAL	0	43,957,917	43,957,917	

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)			
	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	1,081,654	948,219	-12.34%
3	152 Fuel Stock Expenses Undistributed			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	1,134,519	1,177,355	3.78%
9	Transmission Plant (Estimated)	247,241	222,616	-9.96%
10	Distribution Plant (Estimated)	388,888	479,432	23.28%
11	Assigned to Other	9,793	152,065	1452.79%
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed	87,050	142,969	64.24%
16				
17	TOTAL Materials & Supplies	2,949,145	3,122,656	5.88%

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS				
	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	89.6.17			
2	Order Number	5432			
3					
4	Common Equity		35.20%	12.30%	4.33%
5	Preferred Stock		7.60%	8.35%	0.63%
6	Long Term Debt		57.20%	8.45%	4.83%
7	Other		0.00%	0.00%	0.00%
8	TOTAL		100.00%		9.80%
9					
10	Actual at Year End				
11					
12	Common Equity		45%	12.10%	5.45%
13	Preferred Stock		6%	6.89%	0.41%
14	Long Term Debt		49%	7.67%	3.76%
15	Other		0%	0.00%	0.00%
16	TOTAL		100%		9.62%

Sch. 23 **STATEMENT OF CASH FLOWS**

	Description	This year	Last Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	Cash Flows from Operating Activities:			
5	Net Income	478,595,312	(340,925,328)	(171) %
6	Depreciation	260,678,363	269,976,120	4 %
7	Amortization	19,777,921	16,656,468	(16) %
8	Deferred Income Taxes - Net	71,177,224	53,602,328	(25) %
9	Investment Tax Credit Adjustments - Net	(9,931,691)	(9,469,467)	(5) %
10	Change in Operating Receivables - Net	23,103,542	(22,125,449)	(196) %
11	Change in Materials, Supplies & Inventories - Net	15,040,622	4,370,335	(71) %
12	Change in Operating Payables & Accrued Liabilities - Net	(14,852,707)	17,083,086	(215) %
13	Allowance for Funds Used During Construction (AFUDC)	(4,254,834)	(7,327,515)	72 %
14	Change in Other Assets & Liabilities - Net	(2,368,780)	43,858,622	(1,952) %
15	Other Operating Activities (explained on attached page)	(114,554,171)	587,850,509	(613) %
16	Net Cash Provided by/(Used in) Operating Activities	722,410,801	613,549,709	(15) %
17				
18	Cash Inflows/Outflows From Investment Activities:			
19	Construction/Acquisition of Property, Plant and Equipment	(623,525,086)	(581,608,580)	(7) %
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	2,536,209	2,974,015	17 %
23	Investments In and Advances to Affiliates	36,278,212	674,351	(98) %
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	35,228,899	7,935,478	(77) %
27	Net Cash Provided by/(Used in) Investing Activities	(549,481,766)	(570,024,736)	4 %
28				
29	Cash Flows from Financing Activities:			
30	Proceeds from Issuance of:			
31	Long-Term Debt	786,869,662	710,308,943	(10) %
32	Preferred Stock	0	195,189,483	
33	Common Stock	197,423,456	178,226,151	(10) %
34	Other: Intercompany Borrowings	(2,394,699)	10,149,114	(524) %
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(643,972,263)	(820,059,354)	27 %
39	Preferred Stock	(50,000,000)	(56,000,000)	12 %
40	Common Stock			
41	Other: Redemption Premium	(21,790,908)		(100) %
42	Net Decrease in Short-Term Debt	(99,008,768)	165,681,772	(267) %
43	Dividends on Preferred Stock	(39,593,652)	(35,167,657)	(11) %
44	Dividends on Common Stock	(327,084,039)	(404,456,402)	24 %
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	(199,551,211)	(56,127,950)	(72) %
47				
48				
49	Net Increase/(Decrease) in Cash and Cash Equivalents	(26,622,176)	(12,602,977)	(53) %
50	Cash and Cash Equivalents at Beginning of Year	(12,423,732)	179,245	(101) %
51	Cash and Cash Equivalents at End of Year	(39,045,908)	(12,423,732)	(68) %

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	FIRST MORTGAGE BONDS:								
2	4-5/8% Series due 8/1/94	8/64	8/94	15,000,000	13,537,798	13,400,000	4-5/8%	611,308	4.52%
3	4-5/8% Series due 10/1/94	10/64	10/94	30,000,000	19,936,067	20,261,000	4-5/8%	957,535	4.80%
4	5% Series due 10/1/95	10/65	10/95	30,000,000	14,026,006	14,168,000	5%	717,609	5.12%
5	9-3/8% Yen Fin due 7/22/97	7/87	7/97	50,000,000	49,668,437	50,000,000	3.552%	1,777,700	3.58%
6	7% Series due 3/1/98	3/68	3/98	20,000,000	15,982,729	16,000,000	7%	1,121,440	7.02%
7	7-1/2% Series due 5/1/02	5/72	5/02	25,000,000	20,079,174	20,310,000	7-1/2%	1,542,951	7.68%
8	7-3/4% Series due 10/1/02	10/72	10/02	30,000,000	19,434,644	19,744,000	7-3/4%	1,557,209	8.01%
9	Adjust. Rate Series due 11/1/02	9/82	11/02	50,000,000	13,116,905	13,234,000	10.104	1,337,163	10.19%
10	8.271% Series due 10/1/10	4/92	10/10	48,972,000	46,055,762	46,111,000	8.271%	3,819,835	8.29%
11	7.978% Series due 10/1/11	4/92	10/11	4,422,000	4,150,023	4,155,000	7.978%	331,985	8.00%
12	8.493% Series due 10/1/12	4/92	10/12	19,772,000	18,763,496	18,786,000	8.493%	1,597,937	8.52%
13	8.797% Series due 10/1/13	4/92	10/13	16,203,000	15,449,470	15,468,000	8.797%	1,362,731	8.82%
14	8.734% Series due 10/1/14	4/92	10/14	28,218,000	27,003,613	27,036,000	8.734%	2,364,569	8.76%
15	8.294% Series due 10/1/15	4/92	10/15	46,946,000	45,005,022	45,059,000	8.294%	3,742,601	8.32%
16	8.635% Series due 10/1/16	4/92	10/16	18,750,000	18,045,357	18,067,000	8.635%	1,562,253	8.66%
17	8.470% Series due 10/1/17	4/92	10/17	19,609,000	18,911,318	18,934,000	8.470%	1,605,982	8.49%
18	6-3/4% Series due 4/1/05	4/93	4/05	150,000,000	144,269,600	150,000,000	6-3/4%	10,848,000	7.52%
19									
20	Total First Mortgage Bonds			1,076,892,000	503,435,421	510,733,000		36,858,808	7.32%
21									
22	SECURED MEDIUM-TERM NOTES:								
23	8.11% Ser. B due 1/18/94	1/91	1/94	4,000,000	3,976,141	4,000,000	8.11%	333,560	8.39%
24	8.07% Ser. B due 2/1/94	1/91	2/94	10,000,000	9,945,352	10,000,000	8.07%	827,900	8.32%
25	8-7/8% Ser. A due 6/15/94	6/89	6/94	10,000,000	10,465,515	10,000,000	8-7/8%	773,500	7.39%
26	8.47% Ser. B due 1/17/95	1/91	1/95	5,000,000	4,965,176	5,000,000	8.47%	434,000	8.74%
27	8.41% Ser. B due 2/1/95	1/91	2/95	10,000,000	9,930,352	10,000,000	8.41%	862,000	8.68%
28	8.59% Ser. B due 12/26/95	12/90	12/95	3,000,000	3,139,655	3,000,000	8.59%	223,740	7.13%
29	8.60% Ser. B due 12/28/95	12/90	12/95	2,500,000	2,616,379	2,500,000	8.60%	186,675	7.13%
30	8.60% Ser. B due 1/25/96	1/91	1/96	1,000,000	993,535	1,000,000	8.60%	87,620	8.82%
31	8.57% Ser. B due 2/1/96	1/91	2/96	11,000,000	10,928,887	11,000,000	8.57%	960,520	8.79%
32	8.55% Ser. B due 2/1/96	1/91	2/96	3,000,000	2,977,605	3,000,000	8.55%	262,110	8.80%
33	8.69% Ser. C due 7/16/96	7/91	7/96	8,500,000	8,442,477	8,500,000	8.69%	753,100	8.92%
34	8.65% Ser. B due 7/17/96	7/91	7/96	1,000,000	994,982	1,000,000	8.65%	87,760	8.82%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
35	SECURED MEDIUM-TERM NOTES (Cont.):								
36	8.49% Ser. C due 8/15/96	8/91	8/96	14,050,000	13,954,918	14,050,000	8.49%	1,216,730	8.72%
37	8.43% Ser. A due 9/2/96	8/89	9/96	5,000,000	5,228,591	5,000,000	8.43%	378,800	7.24%
38	6.96% Ser. D due 1/22/97	2/92	1/97	1,000,000	912,241	1,000,000	6.96%	91,880	10.07%
39	7.00% Ser. D due 1/27/97	1/92	1/97	15,000,000	14,001,525	15,000,000	7.00%	1,300,350	9.29%
40	7.00% Ser. D due 1/27/97	1/92	1/97	20,000,000	18,668,701	20,000,000	7.00%	1,733,800	9.29%
41	6.99% Ser. D due 2/3/97	1/92	2/97	1,500,000	1,400,152	1,500,000	6.99%	129,870	9.28%
42	6.09% Ser. E due 4/15/97	10/92	4/97	2,000,000	1,791,000	2,000,000	6.09%	179,260	10.01%
43	8.87% Ser. A due 6/20/97	6/91	6/97	20,000,000	19,909,544	20,000,000	8.87%	1,793,800	9.01%
44	8.85% Ser. A due 6/20/97	6/91	6/97	15,000,000	14,917,158	15,000,000	8.85%	1,345,650	9.02%
45	8.78% Ser. B due 6/30/97	6/91	6/97	7,000,000	6,961,340	7,000,000	8.78%	623,070	8.95%
46	8.84% Ser. B due 7/2/97	7/91	7/97	2,000,000	1,988,965	2,000,000	8.84%	179,220	9.01%
47	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	6.12%	629,800	6.35%
48	6.12% Ser. E due 9/29/97	9/92	9/97	3,500,000	3,457,000	3,500,000	6.12%	224,385	6.49%
49	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	6.12%	629,800	6.35%
50	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	6.12%	629,800	6.35%
51	6.14% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	6.14%	631,800	6.37%
52	5.88% Ser. E due 10/15/97	10/92	10/97	1,000,000	907,888	1,000,000	5.88%	76,010	8.37%
53	6.00% Ser. E due 10/15/97	10/92	10/97	2,300,000	2,058,143	2,300,000	6.00%	183,770	8.93%
54	5.88% Ser. E due 10/15/97	10/92	10/97	12,000,000	10,620,435	12,000,000	5.88%	967,320	9.11%
55	8.75% Ser. A due 2/12/98	2/91	2/98	5,000,000	4,957,676	5,000,000	8.75%	445,750	8.99%
56	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,673,027	15,000,000	8.75%	1,337,250	9.11%
57	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,873,027	15,000,000	8.75%	1,355,550	9.11%
58	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,780,527	15,000,000	8.75%	1,376,850	9.32%
59	8.75% Ser. A due 2/12/98	2/91	2/98	10,000,000	9,915,352	10,000,000	8.75%	891,500	8.99%
60	8.81% Ser. C due 3/5/98	8/91	3/98	7,000,000	6,949,128	7,000,000	8.81%	626,640	9.02%
61	8.94% Ser. A due 6/25/98	6/91	6/98	15,000,000	14,909,658	15,000,000	8.94%	1,358,700	9.11%
62	8.90% Ser. C due 6/30/98	6/91	6/98	25,000,000	24,805,815	25,000,000	8.90%	2,263,000	9.12%
63	8.95% Ser. A due 6/30/98	6/91	6/98	5,000,000	4,972,386	5,000,000	8.95%	452,900	9.11%
64	8.95% Ser. A due 6/30/98	6/91	6/98	20,000,000	19,879,544	20,000,000	8.95%	1,813,600	9.12%
65	8.96% Ser. A due 7/3/98	7/91	7/98	8,000,000	7,951,860	8,000,000	8.96%	726,240	9.13%
66	8.94% Ser. C due 7/6/98	7/91	7/98	5,000,000	4,961,163	5,000,000	8.94%	454,600	9.16%
67	8.89% Ser. C due 7/20/98	7/91	7/98	5,000,000	4,961,163	5,000,000	8.89%	452,100	9.11%
68	8.82% Ser. C due 8/3/98	8/91	8/98	5,000,000	4,961,163	5,000,000	8.82%	448,600	9.04%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
69	SECURED MEDIUM-TERM NOTES (Cont.):								
70	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,970,930	4,000,000	8.83%	359,280	9.05%
71	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,968,930	4,000,000	8.83%	358,880	9.04%
72	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,968,930	4,000,000	8.83%	359,280	9.05%
73	8.83% Ser. C due 9/1/98	8/91	9/98	18,000,000	17,860,187	18,000,000	8.83%	1,616,760	9.05%
74	7.45% Ser. D due 1/22/99	1/92	1/99	10,000,000	9,324,350	10,000,000	7.45%	876,200	9.40%
75	7.45% Ser. D due 1/22/99	1/92	1/99	5,000,000	4,662,175	5,000,000	7.45%	458,250	9.83%
76	7.35% Ser. D due 2/1/99	1/92	2/99	4,000,000	3,729,740	4,000,000	7.35%	346,280	9.28%
77	7.45% Ser. D due 2/4/99	2/92	2/99	20,000,000	18,224,829	20,000,000	7.45%	1,839,600	10.09%
78	7.54% Ser. D due 2/15/99	2/92	2/99	15,000,000	13,668,621	15,000,000	7.54%	1,393,950	10.20%
79	7.50% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	7.50%	462,550	10.15%
80	7.49% Ser. D due 2/15/99	2/92	2/99	30,000,000	27,337,242	30,000,000	7.49%	2,772,000	10.14%
81	7.46% Ser. D due 2/15/99	2/92	2/99	10,000,000	9,112,414	10,000,000	7.46%	920,800	10.10%
82	7.45% Ser. D due 2/15/99	2/92	2/99	20,000,000	18,224,829	20,000,000	7.45%	1,839,600	10.09%
83	7.40% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	7.40%	457,250	10.04%
84	7.40% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	7.40%	457,250	10.04%
85	9-1/2% Ser. A due 5/20/99	5/89	5/99	60,000,000	62,718,089	60,000,000	9-1/2%	5,285,400	8.43%
86	9.48% Ser. A due 5/25/99	5/89	5/99	15,000,000	15,680,772	15,000,000	9.48%	1,318,350	8.41%
87	9-1/2% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,680,772	15,000,000	9-1/2%	1,321,200	8.43%
88	9-1/2% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,680,772	15,000,000	9-1/2%	1,321,200	8.43%
89	9.40% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,740,422	15,000,000	9.40%	1,297,800	8.25%
90	8.55% Ser. A due 8/10/99	8/89	8/99	2,000,000	2,090,603	2,000,000	8.55%	157,740	7.55%
91	8.59% Ser. A due 9/1/99	8/89	9/99	10,000,000	10,457,182	10,000,000	8.59%	792,000	7.57%
92	6.51% Ser. E due 9/23/99	9/92	9/99	15,000,000	14,884,500	15,000,000	6.51%	997,350	6.70%
93	6.53% Ser. E due 9/27/99	9/92	9/99	5,000,000	4,944,500	5,000,000	6.53%	336,550	6.81%
94	6.54% Ser. E due 9/27/99	9/92	9/99	5,000,000	4,944,500	5,000,000	6.54%	337,100	6.82%
95	6.55% Ser. E due 9/28/99	9/92	9/99	1,200,000	1,167,300	1,200,000	6.55%	84,600	7.25%
96	6.86% Ser. E due 9/11/00	9/92	9/00	10,000,000	9,914,500	10,000,000	6.86%	700,100	7.06%
97	6.55% Ser. E due 9/15/00	9/92	9/00	5,000,000	4,944,500	5,000,000	6.55%	336,600	6.81%
98	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,825,703	20,000,000	8.90%	1,806,000	9.11%
99	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,825,703	20,000,000	8.90%	1,806,800	9.11%
100	8.88% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,830,703	20,000,000	8.88%	1,802,800	9.09%
101	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,825,703	20,000,000	8.90%	1,806,800	9.11%
102	9.10% Ser. A due 3/1/01	6/91	3/01	5,000,000	4,969,886	5,000,000	9.10%	459,650	9.25%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
103	SECURED MEDIUM-TERM NOTES (Cont.):								
104	9.12% Ser. C due 7/5/01	7/91	7/01	5,000,000	4,959,913	5,000,000	9.12%	462,250	9.32%
105	9.12% Ser. C due 7/5/01	7/91	7/01	10,000,000	9,919,826	10,000,000	9.12%	924,500	9.32%
106	9.06% Ser. B due 7/9/01	7/91	7/01	1,000,000	993,982	1,000,000	9.06%	91,530	9.21%
107	9.15% Ser. C due 7/16/01	7/91	7/01	3,000,000	2,975,948	3,000,000	9.15%	278,250	9.35%
108	9.17% Ser. B due 7/17/01	7/91	7/01	1,000,000	993,732	1,000,000	9.17%	92,670	9.33%
109	9.06% Ser. C due 7/23/01	7/91	7/01	1,000,000	991,983	1,000,000	9.06%	91,840	9.26%
110	9.09% Ser. C due 7/24/01	7/91	7/01	1,000,000	991,983	1,000,000	9.09%	92,140	9.29%
111	9.10% Ser. C due 7/30/01	7/91	7/01	5,000,000	4,959,913	5,000,000	9.10%	461,200	9.30%
112	7.50% Ser. E due 8/1/01	11/92	8/01	2,000,000	1,894,328	2,000,000	7.50%	166,940	8.81%
113	8.99% Ser. C due 8/7/01	8/91	8/01	3,000,000	2,975,948	3,000,000	8.99%	273,420	9.19%
114	9.00% Ser. B due 8/8/01	8/91	8/01	2,500,000	2,484,331	2,500,000	9.00%	227,425	9.15%
115	9.00% Ser. C due 8/8/01	8/91	8/01	500,000	495,991	500,000	9.00%	45,620	9.20%
116	7.18% Ser. D due 8/15/02	8/92	8/02	3,500,000	3,478,125	3,500,000	7.18%	254,415	7.31%
117	7.20% Ser. D due 8/15/02	8/92	8/02	6,000,000	5,962,500	6,000,000	7.20%	437,340	7.33%
118	7.12% Ser. D due 8/15/02	8/92	8/02	4,000,000	3,975,000	4,000,000	7.12%	288,360	7.25%
119	7.20% Ser. D due 8/15/02	8/92	8/02	12,000,000	11,925,000	12,000,000	7.20%	874,680	7.33%
120	7.20% Ser. D due 8/15/02	8/92	8/02	6,500,000	6,459,375	6,500,000	7.20%	473,785	7.33%
121	7.20% Ser. D due 8/15/02	8/92	8/02	10,000,000	9,937,500	10,000,000	7.20%	728,900	7.33%
122	7.18% Ser. D due 8/15/02	8/92	8/02	10,000,000	9,937,500	10,000,000	7.18%	726,900	7.31%
123	7.25% Ser. E due 9/9/02	9/92	9/02	20,000,000	19,849,500	20,000,000	7.25%	1,471,600	7.41%
124	7.21% Ser. E due 9/9/02	9/92	9/02	10,000,000	9,912,000	10,000,000	7.21%	733,600	7.40%
125	7.25% Ser. E due 9/9/02	9/92	9/02	20,000,000	19,849,500	20,000,000	7.25%	1,471,600	7.41%
126	7.14% Ser. E due 9/10/02	9/92	9/02	1,500,000	1,465,125	1,500,000	7.14%	112,110	7.65%
127	6.98% Ser. E due 9/16/02	9/92	9/02	10,000,000	9,912,000	10,000,000	6.98%	710,400	7.17%
128	6.97% Ser. E due 9/16/02	9/92	9/02	2,000,000	1,962,000	2,000,000	6.97%	144,800	7.38%
129	6.95% Ser. E due 9/16/02	9/92	9/02	10,000,000	9,912,000	10,000,000	6.95%	707,400	7.14%
130	7.00% Ser. E due 9/17/02	9/92	9/02	1,000,000	968,250	1,000,000	7.00%	74,560	7.70%
131	6.97% Ser. E due 9/23/02	9/92	9/02	1,500,000	1,465,125	1,500,000	6.97%	109,530	7.48%
132	9.00% Ser. C due 9/1/03	6/91	9/03	55,226,000	46,861,515	46,959,121	9.00%	4,239,939	9.05%
133	7.03% Ser. E due 10/15/03	10/92	10/03	5,000,000	4,033,191	5,000,000	7.03%	498,150	12.35%
134	7.39% Ser. E due 10/21/03	10/92	10/03	5,000,000	4,033,191	5,000,000	7.39%	518,950	12.87%
135	7.27% Ser. E due 10/21/03	10/92	10/03	2,000,000	1,613,276	2,000,000	7.27%	204,800	12.69%
136	7.30% Ser. E due 10/22/03	10/92	10/03	2,000,000	1,613,276	2,000,000	7.30%	205,500	12.74%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
137	SECURED MEDIUM–TERM NOTES (Cont.):								
138	7.86% Ser. D due 2/16/04	2/92	2/04	2,500,000	2,330,463	2,500,000	7.86%	219,650	9.43%
139	7.79% Ser. D due 2/16/04	2/92	2/04	6,000,000	5,465,948	6,000,000	7.79%	541,140	9.90%
140	7.75% Ser. D due 2/16/04	2/92	2/04	3,000,000	2,732,975	3,000,000	7.75%	269,310	9.85%
141	7.81% Ser. D due 2/16/04	2/92	2/04	20,000,000	18,606,209	20,000,000	7.81%	1,752,000	9.42%
142	7.32% Ser. E due 9/3/04	9/92	9/04	7,500,000	7,427,625	7,500,000	7.32%	558,225	7.52%
143	7.11% Ser. E due 9/24/04	9/92	9/04	6,500,000	6,433,875	6,500,000	7.11%	470,470	7.31%
144	7.66% Ser. E due 10/22/04	11/92	10/04	5,000,000	4,734,570	5,000,000	7.66%	418,500	8.84%
145	7.30% Ser. E due 10/22/04	10/92	10/04	10,000,000	8,066,382	10,000,000	7.30%	1,011,900	12.54%
146	7.30% Ser. E due 10/22/04	10/92	10/04	10,000,000	8,066,382	10,000,000	7.30%	1,011,900	12.54%
147	7.53% Ser. E due 10/26/04	10/92	10/04	750,000	604,979	750,000	7.53%	77,888	12.87%
148	7.71% Ser. E due 10/27/04	10/92	10/04	3,250,000	2,621,575	3,250,000	7.71%	344,305	13.13%
149	7.71% Ser. E due 10/27/04	10/92	10/04	3,000,000	2,419,915	3,000,000	7.71%	317,820	13.13%
150	7.60% Ser. E due 11/1/04	11/92	11/04	1,000,000	946,914	1,000,000	7.60%	83,070	8.77%
151	7.72% Ser. E due 11/2/04	11/92	11/04	1,500,000	1,420,371	1,500,000	7.72%	126,480	8.90%
152	7.36% Ser. E due 10/17/05	10/92	10/05	5,000,000	4,033,191	5,000,000	7.36%	502,900	12.47%
153	7.34% Ser. E due 10/17/05	10/92	10/05	5,000,000	4,033,191	5,000,000	7.34%	501,750	12.44%
154	7.67% Ser. C due 1/10/07	1/92	1/07	5,724,000	5,341,355	5,724,000	7.67%	484,537	9.07%
155	7.43% Ser. E due 9/11/07	9/92	9/07	2,000,000	1,961,500	2,000,000	7.43%	152,960	7.80%
156	7.22% Ser. E due 9/18/07	9/92	9/07	2,500,000	2,458,250	2,500,000	7.22%	185,150	7.53%
157	7.27% Ser. E due 9/24/07	9/92	9/07	4,000,000	3,948,500	4,000,000	7.27%	296,560	7.51%
158	9.15% Ser. C due 8/9/11	8/91	8/11	8,000,000	7,925,861	8,000,000	9.15%	740,240	9.34%
159	8.95% Ser. C due 9/1/11	8/91	9/11	25,000,000	24,828,315	25,000,000	8.95%	2,256,250	9.09%
160	8.95% Ser. C due 9/1/11	8/91	9/11	20,000,000	19,870,852	20,000,000	8.95%	1,804,000	9.08%
161	8.92% Ser. C due 9/1/11	8/91	9/11	20,000,000	19,814,652	20,000,000	8.92%	1,804,200	9.11%
162	8.29% Ser. C due 12/30/11	12/91	12/11	3,000,000	2,795,607	3,000,000	8.29%	270,960	9.69%
163	8.26% Ser. C due 1/10/12	1/92	1/12	1,000,000	931,901	1,000,000	8.26%	90,000	9.66%
164	8.28% Ser. C due 1/10/12	1/92	1/12	2,000,000	1,865,802	2,000,000	8.28%	180,200	9.66%
165	8.25% Ser. C due 2/1/12	1/92	2/12	3,000,000	2,795,702	3,000,000	8.25%	269,700	9.65%
166	8.53% Ser. C due 12/16/21	12/91	12/21	15,000,000	13,978,039	15,000,000	8.53%	1,380,300	9.87%
167	8.375% Ser. C due 12/31/21	12/91	12/21	5,000,000	4,659,346	5,000,000	8.375%	451,850	9.70%
168	8.26% Ser. C due 1/7/22	1/92	1/22	5,000,000	4,664,504	5,000,000	8.26%	445,250	9.55%
169	8.27% Ser. C due 1/10/22	1/92	1/22	4,000,000	3,727,603	4,000,000	8.27%	357,040	9.58%
170	8.05% Ser. E due 9/1/22	9/92	9/22	15,000,000	14,862,000	15,000,000	8.05%	1,219,800	8.21%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
171	SECURED MEDIUM-TERM NOTES (Cont.):								
172	8.11% Ser. E due 9/9/22	9/92	9/22	12,000,000	11,884,500	12,000,000	8.11%	983,640	8.28%
173	8.07% Ser. E due 9/9/22	9/92	9/22	8,000,000	7,914,500	8,000,000	8.07%	653,280	8.25%
174	8.12% Ser. E due 9/9/22	9/92	9/22	50,000,000	49,599,500	50,000,000	8.12%	4,096,000	8.26%
175	8.05% Ser. E due 9/14/22	9/92	9/22	10,000,000	9,899,500	10,000,000	8.05%	814,000	8.22%
176	8.08% Ser. E due 10/14/22	10/92	10/22	26,000,000	20,390,094	26,000,000	8.08%	2,715,700	13.32%
177	8.08% Ser. E due 10/14/22	10/92	10/22	25,000,000	19,584,706	25,000,000	8.08%	2,614,250	13.35%
178	6.99% Ser. E due 1/25/00	1/93	1/00	10,000,000	9,940,000	10,000,000	6.99%	710,000	7.14%
179	6.97% Ser. E due 1/28/00	1/93	1/00	1,000,000	994,000	1,000,000	6.97%	71,000	7.14%
180	7.11% Ser. E due 1/20/00	1/93	1/00	10,000,000	9,940,000	10,000,000	7.11%	722,100	7.26%
181	7.13% Ser. E due 1/20/00	1/93	1/00	10,000,000	9,940,000	10,000,000	7.13%	724,100	7.28%
182	8.23% Ser. E due 1/20/23	1/93	1/23	4,000,000	3,970,000	4,000,000	8.23%	331,920	8.36%
183	7.36% Ser. E due 1/27/03	1/93	1/03	3,000,000	2,981,250	3,000,000	7.36%	223,500	7.50%
184	8.23% Ser. E due 1/20/23	1/93	1/23	5,000,000	4,962,500	5,000,000	8.23%	414,900	8.36%
185	7.43% Ser. E due 1/24/05	1/93	1/05	2,500,000	2,484,375	2,500,000	7.43%	187,750	7.56%
186	7.21% Ser. E due 1/19/00	1/93	1/00	25,000,000	24,850,000	25,000,000	7.21%	1,817,750	7.31%
187	7.40% Ser. E due 1/22/03	1/93	1/03	1,000,000	993,750	1,000,000	7.40%	74,900	7.54%
188	8.13% Ser. E due 1/22/13	1/93	1/13	10,000,000	9,925,000	10,000,000	8.13%	820,700	8.27%
189	7.43% Ser. E due 1/24/05	1/93	1/05	1,000,000	993,750	1,000,000	7.43%	75,100	7.56%
190	7.07% Ser. E due 1/25/00	1/93	1/00	10,500,000	10,437,000	10,500,000	7.07%	754,005	7.22%
191	5.85% Ser. F due 4/17/00	8/93	4/00	3,000,000	2,844,883	3,000,000	5.85%	203,700	7.16%
192	5.85% Ser. F due 4/17/00	8/93	4/00	3,000,000	2,844,883	3,000,000	5.85%	203,700	7.16%
193	5.85% Ser. F due 4/17/00	8/93	4/00	5,000,000	4,741,471	5,000,000	5.85%	339,500	7.16%
194	5.85% Ser. F due 4/17/00	8/93	4/00	5,000,000	4,741,471	5,000,000	5.85%	339,500	7.16%
195	6.05% Ser. F due 4/17/00	8/93	4/00	15,000,000	14,224,413	15,000,000	6.05%	1,049,550	7.38%
196	6.05% Ser. F due 4/17/00	8/93	4/00	5,000,000	4,804,610	5,000,000	6.05%	338,000	7.03%
197	6.05% Ser. F due 4/17/00	8/93	4/00	15,000,000	14,224,413	15,000,000	6.05%	1,049,550	7.38%
198	6.05% Ser. F due 4/17/00	8/93	4/00	25,000,000	23,755,404	25,000,000	6.05%	1,740,250	7.33%
199	6.02% Ser. F due 5/15/01	7/93	5/01	4,500,000	4,265,074	4,500,000	6.02%	309,555	7.26%
200	6.31% Ser. F due 7/28/03	7/93	7/03	18,000,000	17,055,796	18,000,000	6.31%	1,269,000	7.44%
201	6.31% Ser. F due 7/28/03	7/93	7/03	18,000,000	17,055,796	18,000,000	6.31%	1,269,000	7.44%
202	6.31% Ser. F due 7/28/03	7/93	7/03	6,000,000	5,685,265	6,000,000	6.31%	423,000	7.44%
203	6.31% Ser. F due 7/28/03	7/93	7/03	1,000,000	947,544	1,000,000	6.31%	70,500	7.44%
204	6.34% Ser. F due 7/28/03	7/93	7/03	2,000,000	1,895,088	2,000,000	6.34%	141,620	7.47%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
205	SECURED MEDIUM-TERM NOTES (Cont.):								
206	6.34% Ser. F due 7/28/03	7/93	7/03	19,000,000	18,003,340	19,000,000	6.34%	1,345,390	7.47%
207	6.34% Ser. F due 7/28/03	7/93	7/03	10,000,000	9,475,442	10,000,000	6.34%	708,100	7.47%
208	6.34% Ser. F due 7/28/03	7/93	7/03	4,000,000	3,790,177	4,000,000	6.34%	283,240	7.47%
209	6.34% Ser. F due 7/28/03	7/93	7/03	2,000,000	1,895,088	2,000,000	6.34%	141,620	7.47%
210	7.25% Ser. F due 8/1/13	7/93	8/13	10,000,000	9,462,942	10,000,000	7.25%	778,400	8.23%
211	7.25% Ser. F due 8/1/13	7/93	8/13	10,000,000	9,462,942	10,000,000	7.25%	778,400	8.23%
212	7.25% Ser. F due 8/1/13	7/93	8/13	10,000,000	9,462,942	10,000,000	7.25%	778,400	8.23%
213	7.25% Ser. F due 8/1/13	7/93	8/13	10,000,000	9,462,942	10,000,000	7.25%	778,400	8.23%
214	6.72% Ser. F due 9/14/23	9/93	9/23	2,000,000	1,986,000	2,000,000	6.72%	135,500	6.82%
215	6.75% Ser. F due 10/26/23	10/93	10/23	12,000,000	11,916,000	12,000,000	6.75%	816,600	6.85%
216	6.75% Ser. F due 10/26/23	10/93	10/23	20,000,000	19,860,000	20,000,000	6.75%	1,361,000	6.85%
217	6.75% Ser. F due 10/26/23	10/93	10/23	16,000,000	15,888,000	16,000,000	6.75%	1,088,800	6.85%
218	6.75% Ser. F due 9/14/23	9/93	9/23	5,000,000	4,900,933	5,000,000	6.75%	345,350	7.05%
219	6.75% Ser. F due 9/14/23	9/93	9/23	2,000,000	1,986,000	2,000,000	6.75%	136,100	6.85%
220	7.23% Ser. F due 8/16/23	8/93	8/23	15,000,000	14,383,831	15,000,000	7.23%	1,136,850	7.90%
221	7.24% Ser. F due 8/16/23	8/93	8/23	30,000,000	28,767,662	30,000,000	7.24%	2,276,700	7.91%
222	7.26% Ser. F due 7/21/23	7/93	7/23	27,000,000	25,549,944	27,000,000	7.26%	2,084,940	8.16%
223	7.26% Ser. F due 7/21/23	7/93	7/23	11,000,000	10,409,236	11,000,000	7.26%	849,420	8.16%
224	7.37% Ser. F due 8/11/23	8/93	8/23	15,500,000	14,863,292	15,500,000	7.37%	1,197,220	8.05%
225	7.40% Ser. F due 7/28/23	7/93	7/23	2,000,000	1,892,588	2,000,000	7.40%	157,380	8.32%
226	4.53% Ser. F due 9/16/96	9/93	9/96	32,000,000	30,765,506	32,000,000	4.53%	1,904,960	6.19%
227	4.53% Ser. F due 9/16/96	9/93	9/96	25,000,000	24,035,551	25,000,000	4.53%	1,488,250	6.19%
228	4.53% Ser. F due 9/16/96	9/93	9/96	40,000,000	38,456,882	40,000,000	4.53%	2,381,200	6.19%
229	4.53% Ser. F due 9/16/96	9/93	9/96	25,000,000	24,035,551	25,000,000	4.53%	1,488,250	6.19%
230									
231									
232	Total Secured Medium-Term Notes			1,969,000,000	1,897,871,563	1,960,733,121		160,009,749	8.43%
233									
234									
235									
236									
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238									

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
239	POLL. CTRL. OBLIGATIONS – SECURED BY PLEDGED FIRST MORTGAGE BONDS:								
240	6–1/8% Series due 2/04 Emery	2/74	2/04	14,000,000	13,170,808	13,425,000	6–1/8%	841,211	6.39%
241	6–1/8% Series due 2/04 Carbon	2/74	2/04	11,000,000	9,383,894	9,565,000	6–1/8%	599,343	6.39%
242	6–1/8% Series due 2/04 Lincoln	2/74	2/04	16,000,000	15,034,833	15,325,000	6–1/8%	960,263	6.39%
243	6–3/8% Series due 11/06 Emery	11/76	11/06	50,000,000	48,728,350	50,000,000	6–3/8%	3,285,000	6.74%
244	5.90% Series due 4/08 Emery	4/78	4/08	42,000,000	41,224,321	42,000,000	5.90%	2,534,280	6.15%
245	10.70% Series due 9/14 Emery	9/84	9/14	16,750,000	15,736,753	16,750,000	10.70%	1,912,180	12.15%
246	8–1/4% Series due 6/17 Emery	6/87	6/17	46,500,000	44,325,559	46,500,000	8–1/4%	2,783,955	6.28%
247	8–5/8% Series due 6/17 Emery	6/87	6/17	16,400,000	14,714,206	16,400,000	8–5/8%	1,049,600	7.13%
248	8–5/8% Series due 6/17 Lincln	6/87	6/17	8,300,000	7,348,041	8,300,000	8–5/8%	541,326	7.37%
249	6.600% Series due 5/94 Moffat	5/78	5/94	1,660,000	1,658,011	1,660,000	6.600%	110,639	6.67%
250	6.650% Series due 5/95 Moffat	5/78	5/95	1,770,000	1,767,880	1,770,000	6.650%	118,502	6.70%
251	6.700% Series due 5/96 Moffat	5/78	5/96	1,890,000	1,887,736	1,890,000	6.700%	127,292	6.74%
252	6.700% Series due 5/97 Moffat	5/78	5/97	2,015,000	2,012,586	2,015,000	6.700%	135,589	6.74%
253	6.700% Series due 5/98 Moffat	5/78	5/98	2,150,000	2,147,424	2,150,000	6.700%	144,588	6.73%
254	6.875% Series due 5/08 Moffat	5/78	5/08	35,030,000	34,988,037	35,030,000	6.875%	2,412,516	6.90%
255	6–3/8% Series due 1/1/07	1/77	1/07	17,000,000	7,974,431	8,190,000	6–3/8%	538,656	6.75%
256									
257									
258	Total Poll Ctrl Oblg Sec by FMB			282,465,000	262,102,870	270,970,000		18,094,940	6.90%
259									
260									
261	FIXED RATE POLL CTRL REVENUE BONDS:								
262	6% Series due 10/1/03	10/73	10/03	25,000,000	20,964,726	21,260,000	6%	1,297,073	6.19%
263									
264									
265	Total Fixed Rate PCRB's			25,000,000	20,964,726	21,260,000		1,297,073	6.19%
266									
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LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
273	VARIABLE RATE POLL CTRL REVENUE BONDS:								
274	Var. Rate Emery Co. 1991	5/91	7/15	45,000,000	52,440,000	45,000,000	8.915%	4,011,750	7.65%
275	Var. Rate Lincoln Co. 1991	1/91	1/16	45,000,000	52,440,000	45,000,000	8.915%	4,011,750	7.65%
276	Var. Rate Forsyth 1988	1/88	1/18	45,000,000	44,619,802	45,000,000	8.084%	3,637,800	8.15%
277	Var. Rate Sweetwater A	1/88	1/17	50,000,000	49,577,557	50,000,000	3.038%	1,519,000	3.06%
278	Var. Rate Gillette (Wyodak)	1/88	1/18	41,200,000	40,972,358	41,200,000	10.226%	4,213,112	10.28%
279	Var. Rate Sweetwater 88B/Converse	1/88	1/14	28,500,000	27,429,996	28,500,000	2.793%	795,960	2.90%
280	Var. Rate Sweetwater C	12/84	12/14	15,000,000	14,772,113	15,000,000	2.661%	399,150	2.70%
281	Var. Rate Forsyth 1986	12/86	12/16	8,500,000	8,195,176	8,500,000	3.192%	271,320	3.31%
282	Var. Rate Sweetwater 1990A	7/90	7/19	21,100,000	18,414,000	18,600,000	2.980%	554,280	3.01%
283	Var. Rate Sweetwater 1990A	7/90	7/15	70,000,000	68,965,857	70,000,000	8.574%	6,001,800	8.70%
284	Var. Rate Sweetwater 1992A	9/92	4/05	9,335,000	9,053,325	9,335,000	3.093%	288,732	3.19%
285	Var. Rate Converse 1992	9/92	7/06	22,485,000	21,968,372	22,485,000	3.318%	746,052	3.40%
286	Var. Rate Sweetwater 1992B	9/92	12/05	6,305,000	6,172,572	6,305,000	3.310%	208,696	3.38%
287									
288									
289	Total Variable Rate PCRB's			407,425,000	415,021,128	404,925,000		26,659,402	6.42%
290									
291									
292	TOTAL BONDS (Acct. 221)			3,760,782,000	3,099,395,708	3,168,621,121		242,919,972	7.84%
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Sch. 25

PREFERRED STOCK

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value(a)	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	5% cumulative preferred	(b)	126,533	100.00	110.00	12,555,021	5.00%	12,653,300	632,665	5.04%
2	Serial preferred, cumulative:									
3	4.52% Series	11/55	2,065	100.00	103.50	196,824	4.52%	206,500	9,334	4.74%
4	7.00% Series	(c)	18,060	100.00	None	1,806,000	7.00%	1,806,000	126,420	7.00%
5	6.00% Series	(c)	5,932	100.00	None	593,200	6.00%	593,200	35,592	6.00%
6	5.00% Series	(c)	42,000	100.00	100.00	4,200,000	5.00%	4,200,000	210,000	5.00%
7	5.40% Series	(c)	65,960	100.00	101.00	6,596,000	5.40%	6,596,000	356,184	5.40%
8	4.72% Series	8/63	69,890	100.00	103.50	6,958,651	4.72%	6,989,000	329,881	4.74%
9	4.56% Series	2/65	84,592	100.00	102.34	8,410,129	4.56%	8,459,200	385,740	4.59%
10	8.92% Series	11/69	69,375	100.00	102.37	6,923,997	8.92%	6,937,500	618,825	8.94%
11	9.08% Series	6/71	164,893	100.00	104.02	16,440,752	9.08%	16,489,300	1,497,228	9.11%
12	7.96% Series	10/72	135,176	100.00	103.39	13,492,533	7.96%	13,517,600	1,076,001	7.97%
13										
14	No par serial preferred cumulative:									
15	$2.13 Series	5/77	666,210	25.00	26.07	15,992,249	8.52%	16,655,250	1,419,027	8.87%
16	$7.12 Series	3/87	440,000	100.00	107.12	43,510,042	6.88%	44,000,000	3,026,000	6.95%
17	$1.28 Series	9/60	381,220	25.00	26.35	9,530,500	5.12%	9,530,500	487,962	5.12%
18	$1.18 Series	5/62	420,116	25.00	26.15	10,502,900	4.72%	10,502,900	495,737	4.72%
19	$1.16 Series	8/64	193,102	25.00	26.11	4,827,550	4.64%	4,827,550	223,998	4.64%
20	$1.76 Series	3/68	393,868	25.00	25.96	9,846,700	7.04%	9,846,700	693,208	7.04%
21	$1.98 Series – 1971	3/71	501,998	25.00	26.21	12,549,950	7.92%	12,549,950	993,956	7.92%
22	$7.70 Series	8/91	1,000,000	100.00	100.00	99,088,457	7.70%	100,000,000	7,700,000	7.77%
23	$1.98 Series – 1992	5/92	5,000,000	25.00	N. A.	120,787,500	7.92%	125,000,000	9,900,000	8.20%
24	$7.48 Series	6/92	750,000	100.00	N. A.	73,684,265	7.48%	75,000,000	5,610,000	7.61%
25	DARTS Series A	3/87	500	100,000.00	100,000.00	49,167,311	Variable	50,000,000	1,783,005	3.63%
26	DARTS Series B	3/87	500	100,000.00	N. A.	49,167,311	Variable	0	292,640	0.60%
27	MAPS Series C	10/90	500	No Par	100,000.00	49,241,397	Variable	50,000,000	1,583,450	3.22%
28										
29										
30										
31										
32										
33	TOTAL		10,532,490			626,069,239		586,360,450	39,486,852	6.31%

(a) Par or Stated Value
(b) Replaced preferred stock issues sold in the 1920's and 1930's.
(c) Replaced an issue of The California Oregon Power Company as a result of merger with Pacific Power.

Sch. 26

COMMON STOCK

Line		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Low	Price/ Earnings Ratio
4	January	270,658,820	11.19	0.18			20.125	18.875	
6	February	271,151,293	11.03	0.10			20.625	16.875	
8	March	271,661,313	11.15	0.11	0.270	69.23%	18.250	17.625	11.5
10	April	271,767,926	11.27	0.09			19.125	17.500	
12	May	272,604,781	11.10	0.09			18.250	17.375	
14	June	273,251,598	11.23	0.12	0.270	10.00%	19.125	17.625	15.3
16	July	273,399,868	11.23	0.13			19.375	18.500	
18	August	273,752,752	11.22	0.12			20.125	18.500	
20	September	274,316,705	11.69	0.29	0.270	50.00%	20.750	19.375	9.3
22	October	280,227,892	11.82	0.12			20.125	19.250	
24	November	280,577,166	11.68	0.14			19.625	18.250	
26	December	280,968,460	11.80	0.11	0.270	72.97%	19.875	18.750	13.0
33	TOTAL Year End	274,550,828	11.80	1.60	1.080	67.50%	20.750	16.875	13.0

Sch. 27

OTHER CAPITAL

	Description	Outstanding Per Balance Sheet	Cost%	Weighted Cost%
1	Account 212 – Installments Received on Capital Stock – Common	216,601		
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33	TOTAL	216,601		

Sch. 28	MONTANA EARNED RATE OF RETURN				
		Description	Last Year	This Year	% Change
		Rate Base (Year-end Average)			
1					
2	101	Plant in Service	144,430,578	160,093,305	10.84%
3	108	(Less) Accumulated Depreciation	(43,676,896)	(49,555,745)	13.46%
4		**NET Plant in Service**	100,753,682	110,537,560	9.71%
5					
6		Additions			
7	151, 154	Materials & Supplies	3,031,886	3,156,448	4.11%
8	165	Prepayments	641,648	606,150	-5.53%
9		Other Additions	4,206,719	6,443,475	53.17%
10		**TOTAL Additions**	7,880,253	10,206,073	29.51%
11					
12		Deductions			
13	190	Accumulated Deferred Income Taxes	(4,869,626)	(5,548,711)	13.95%
14	252	Customer Advances for Construction	(50,417)	(32,571)	-35.40%
15	255	Accumulated Def. Investment Tax Credits	(732,605)	(699,456)	-4.52%
16		Other Deductions	(172,124)	(358,219)	108.12%
17		**TOTAL Deductions**	(5,824,772)	(6,638,957)	13.98%
18		**TOTAL Rate Base**	102,809,163	114,104,676	10.99%
19					
20		**Net Earnings**	7,574,170	10,195,741	34.61%
21					
22		**Rate of Return on Average Rate Base**	7.37%	8.94%	21.29%
23					
24		**Rate of Return on Average Equity**	6.24%	10.59%	69.59%
25					
26		**Major Normalizing Adjustments & Commission**			
27		**Ratemaking adjustments to Utility Operations**			
28		**Commission Ordered / Allowed Ratemaking Adj.**			
29		**- Malin Midpoint Adj.**	31,000	18,421	-40.58%
30		**- Unbilled Revenue Adj.**	100,138	0	-100.00%
31		**- Advertising Expense Adj.**	(2,095)	(2,656)	26.78%
32		**- Present Rates Adj.**	22,583	0	-100.00%
33		**- Weather Normalization Adj.**	536,125	(112,653)	-121.01%
34		**- Bridger Coal Adj.**	13,167	0	-100.00%
35		**- Production Cost Study Adj.**	705,090	171,467	-75.68%
36		**- Interest Expense Adj.**	287,394	19,557	-93.20%
37					
38					
39		**Other Company Ratemaking Adjustments**			
40		**- Other Adjustments**	333,702	(472,609)	-241.63%
41					
42					
43					
44					
45		**Adjusted Net Earnings**	9,601,274	9,817,268	2.25%
46					
47		**- Associated Rate Base Adjustments for the**	4,431,242	3,098,178	-30.08%
48		**above Reference Ratemaking Adjustments**			
49		**Adjusted Rate Base**	107,240,405	117,202,854	9.29%
50		**Adjusted Rate of Return on Average Rate Base**	8.95%	8.38%	-6.44%
51					
52		**Adjusted Rate of Return on Average Equity**	10.75%	9.34%	-13.06%

PACIFICORP
State of Montana - Electric Utility
Schedule 28 Detail for Other Rate Base Additions / Deductions

		Last Year	This Year
1	Rate Base:		
2	Plant Held for Future Use	94,183	89,315
3	Misc Deferred Debits	1,909,370	1,336,118
4	Acquisition Adjustment	352,644	1,508,007
5	Nuclear Fuel	15,738	0
6	Working Capital (1)	1,358,042	1,826,030
7	Weatherization Loans	125,344	946,728
8	Unreocered Plant - Trojan	351,398	737,277
9	Total Other Additions	4,206,719	6,443,475
10			
11	Deductions:		
12	Accumulated Prov. - Trojan	(172,124)	(358,219)
13	Total Other Deductions	(172,124)	(358,219)
			0

(1) The Company does not have a specific Commission order authorizing the inclusion of cash working capital in rate base. However, cash working capital has been allowed in Company's previously authorized results (reference rate filings for Docket No. 87.12.80, Order No. 5326 and for Docket No. 89.6.17, Order No. 5432).

Sch. 29 MONTANA COMPOSITE STATISTICS

		Description	Amount
2		**Plant (Intrastate Only)**	
4	101	Plant in Service	305,187,689
5	107	Construction Work in Progress	4,035,685
6	114	Plant Acquisition Adjustments	-
7	105	Plant Held for Future Use	-
8	154, 156	Materials & Supplies	2,335,710
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(78,733,883)
11	252	Contributions in Aid of Construction	(2,983,849)
13		NET BOOK COSTS	229,841,352
16		**Revenues & Expenses**	
18	400	Operating Revenues	33,826,586
20	403 - 407	Depreciation & Amortization Expenses	4,230,908
21	409	Federal & State Income Taxes	3,592,200
22	408	Other Taxes	4,985,771
23		Other Operating Expenses	16,756,607
24		TOTAL Operating Expenses	29,565,486
26		Net Operating Income	4,261,100
28	415-421.1	Other Income	-
29	421.2-426.5	Other Deductions	14,047
31		NET INCOME	4,247,053
34		**Customers (Intrastate Only)**	
36		Year End Average:	
37		Residential	26,268
38		Commercial	4,832
39		Industrial	211
40		Other	42
42		TOTAL NUMBER OF CUSTOMERS	31,353
45		**Other Statistics (Intrastate Only)**	
47		Average Annual Residential Use (Kwh)	12,669
48		Average Annual Residential Cost per (Kwh) (Cents) *	4.78
49		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
50		Average Residential Monthly Bill	$50.42
51		Gross Plant per Customer	$9,734

Sch. 30

MONTANA CUSTOMER INFORMATION

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Bigfork	N. A.	2,403	687	31	3,121
2	Columbia Falls	N. A.	2,765	631	43	3,439
3	Kalispell	N. A.	10,414	2,832	286	13,532
4	Kila	N. A.	228	44		272
5	Lakeside	N. A.	993	250	7	1,250
6	Libby	N. A.	4,388	1,232	70	5,690
7	Rollins	N. A.	273	55	4	332
8	Sommers	N. A.	600	172	9	781
9	Swan Lake	N. A.	180	40	1	221
10	Whitefish	N. A.	4,753	1,204	32	5,989
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33	TOTAL Montana Customers		26,997	7,147	483	34,627

Sch. 31	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning	Year End	Average
1	Bigfork	2	1	2
2	Facilities Engineering	1	1	1
3	Kalispell District	35	38	37
4	Kalispell Power	5	5	5
5	Libby District	10	10	10
6	Montana Area	6	6	6
7	Whitefish District	10	12	11
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53	TOTAL Montana Employees	69	73	71

Sch. 32 MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) — In (000's)

	Project Description	Total Company	Total Montana
1	RESOURCE ACQUISITION-JAMES RIVER CAMAS	$13,471	233
2	BUTLERVILLE 138/46 KV SUBS	10,825	187
3	JORDAN 138/46 KV SUBS	8,040	139
4	CENTRALIA MINE-FLEET (1) SHOVEL/(4) TRUCKS)	7,661	127
5	GADSBY - NATURAL GAS PIPELINE	6,950	120
6	APS COMBUSTION TURBINES - ENGINEERING	6,754	117
7	COTTONWOOD PREP PLANT - FINE COAL CIRCUIT	6,155	102
8	NAUGHTON 270: S02 COMPLIANCE ADDITIONS	5,595	97
9	NAUGHTON:ASH POND IMPROVMNTS/EXPANSION	5,457	94
10	LAMPO 138/46 KV SUBSTATION	4,567	79
11	GADSBY UNIT 1 STARTUP.	4,438	77
12	HUNTINGTON UNIT #1 CONDENSATE POLISHERS	4,278	74
13	GLEN CANYON-NAVAJO TIE LINE	4,245	74
14	DJ - COAL HANDLING SYSTEM UPGRADE	4,037	70
15	BUILD DISTRICT/AREA/DIVISION OFFICE-YAKIMA	3,934	67
16	HUNTINGTON PLANT #2 COOLING TOWER REPLMT	3,842	67
17	GADSBY UNIT 2 STARTUP	3,166	55
18	COTTONWOOD MINE-MINE EXTENSION	2,866	48
19	BEN LOMOND-STATION SVC EQUIP FAILUR	2,793	48
20	CENTRALIA MINE-HAUL TRUCK 190 TON (REPL-2)	2,718	45
21	DEER CREEK MINE-LONGWALL FACE CONVEYOR	2,489	41
22	DEER CREEK MINE-MINE EXTENSION	2,175	36
23	HUNTINGTON UNIT #2 CONDENSATE POLISHER	2,105	36
24	HUNTER 302 - ECONOMIZER REPLACEMENT	2,020	35
25	DJ - INSTALL CONTINUOUS EMISSION MONITORS	1,958	34
26	VEOLKER AVE SUB-CONSTR 116-13.2KV SUB	1,873	32
27	MERIDIAN TO LN PINE 230 KV	1,821	32
28	HUNTER 301 CONDENSATE POLISHER ADDITION	1,698	29
29	DJ#2 - TURBINE/GENERATOR INSPECTION	1,682	29
30	JERUSALEM-EPHRAIM TAP: REBUILD 46KV LINE	1,567	27
31	DEER CREEK MINE-WATER TREATMENT FACILITY	1,562	26
32	NW PWR FACILITY - W. SIDE COMBUSTION TURBINES	1,558	27
33	HUNTER CONDENSATE POLISHER REGEN SYS	1,551	27
34	AMERICAN CAN 69 KV RECONDUCTOR	1,519	26
35	HUNTINGTON #1 ASH & PYRITES SYST. REPL	1,480	26
36	CENTRALIA MINE-ROM FEEDER BREAKER SYS	1,434	24
37	GADSBY 1&2 COMMON STARTUP.	1,425	25
38	COTTONWOOD MINE-SURFACE CONVEYOR TUBE	1,409	23
39	MCCLELLAND CIR BRKR, 6TH SO-SNARR LN REBUILD	1,378	24
40	RIVERDALE SUB - REBUILD SUBSTATION	1,351	23
41	WALLULA SUB-INSTALL 230KV RING BUS	1,336	23
42	CENTRAL PROCESSOR UPGRADE	1,311	22
43	JCB MAJOR OH/RUNNER REPLACEMENT	1,281	22
44	NAUGHTON 271: TURBINE REPAIR	1,277	22
45	CARBON PLT BOILER MAKEUP WATER DEMINERALIZER	1,162	20
46	HUNTER 302 CONDENSATE POLISHER ADDITION	1,140	20
47	COTTONWOOD MINE-MAINLINE ACCESS ENTRIES	1,126	19
48	WYODAK ACC VARIABLE SPEED DRIVES	1,109	19
49	HIGHLAND-AMER FORK: INSTALL NEW 46 KV FEEDER	1,091	19
50	BPA ALVEY-DIXON 500KV LN 90 CONST 58MI	1,075	19
51	DJ #4 - ASH POND 4B RELINING	1,036	18
52	ALL OTHER	582,325	N/A
53	TOTAL	741,115	2,725

Sch. 33 TOTAL SYSTEM & MONTANA PEAK AND ENERGY

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale
1	Jan.	13	0800	7,440	5,740,852	1,195,442
2	Feb.	16	0800	7,401	4,935,324	959,888
3	Mar.	2	0800	6,805	5,086,531	1,077,742
4	Apr.	19	0800	6,261	4,963,618	1,245,615
5	May	24	1400	5,943	4,669,680	956,726
6	Jun.	28	1300	6,395	4,803,483	1,103,219
7	Jul.	19	1300	6,567	5,338,882	1,343,586
8	Aug.	2	1400	6,815	5,315,427	1,292,241
9	Sep.	8	1700	6,543	5,146,796	1,267,692
10	Oct.	27	0800	6,379	5,099,964	1,173,808
11	Nov.	24	0800	7,591	5,312,296	1,056,404
12	Dec.	20	0900	7,296	5,582,112	1,088,350
13	TOTAL				61,994,965	13,760,713

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale
14	Jan.	13	0900	174	110,658	20,480
15	Feb.	16	0800	165	94,470	16,438
16	Mar.	1	0900	145	95,033	18,431
17	Apr.	6	0900	118	88,183	21,214
18	May	3	0900	108	82,416	16,411
19	Jun.	29	1300	104	81,691	18,914
20	Jul.	20	1200	101	85,230	23,009
21	Aug.	25	1000	100	83,481	22,202
22	Sep.	23	0900	113	85,001	21,842
23	Oct.	29	0900	119	86,243	20,246
24	Nov.	24	0900	170	103,774	18,247
25	Dec.	6	0900	147	108,140	18,783
26	TOTAL				1,104,320	236,217

Sch. 34 TOTAL SYSTEM Sources & Disposition of Energy

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	48,482,816	Sales to Ultimate Consumers	
3	Nuclear	(1,114)	(Include Interdepartmental)	42,413,098
4	Hydro - Conventional	3,755,478		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	84,961	for Resale	1,188,204
7	(Less) Energy for Pumping			
8	NET Generation	52,322,141	Non-Requirements Sales	
9	Purchases	9,744,113	for Resale	13,760,713
10	Power Exchanges			
11	Received	14,264,149	Energy Furnished	
12	Delivered	13,965,052	Without Charge	0
13	NET Exchanges	299,097		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	10,820,764	Electric Utility	83,159
16	Delivered	10,820,764		
17	NET Transmission Wheeling	0	Total Energy Losses	4,549,791
18	Transmission by Others Losses	(370,386)		
19	TOTAL	61,994,965	TOTAL	61,994,965

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak – MW	Annual Energy – MWH
1	Thermal	Cholla Unit No. 4	Joseph City, Arizona	382.0	2,426,026
2	Thermal	Craig Units #1 & #2	Craig, Colorado	181.0	1,246,741
3	Thermal	Hayden Plant	Hayden, Colorado	95.0	518,878
4	Thermal	Colstrip Unit #3 & #4	Colstrip, Montana	154.0	836,270
5	Thermal	Carbon Plant	Castle Gate, Utah	181.0	1,359,725
6	Thermal	Gadsby Plant	Salt Lake City, Utah	100.0	410,124
7	Thermal	Hunter Plant	Castle Dale, Utah	1,038.0	7,884,722
8	Thermal	Huntington Plant	Huntington, Utah	829.0	6,343,935
9	Thermal	Centralia Plant	Centralia, Washington	669.0	4,225,123
10	Thermal	Dave Johnston Plant	Glenrock, Wyoming	805.0	6,043,644
11	Thermal	Jim Bridger Plant	Rock Springs, Wyoming	1,409.0	10,185,833
12	Thermal	Wyodak Plant	Gillette, Wyoming	315.0	2,288,497
13	Thermal	Naughton Plant	Kemmerer, Wyoming	677.0	4,565,150
14	Geothermal	Blundell Plant	Milford, Utah	27.0	148,148
15	Combustion Turbine	Little Moutain Plant	Ogden, Utah	15.0	84,961
16	Nuclear	Trojan Plant	Rainier, Oregon	0.0	(1,114)
17	Hydro	Copco #1	Copco, California	26.0	99,705
18	Hydro	Copco #2	Copco, California	30.0	126,169
19	Hydro	Fall Creek	Copco, California	2.2	12,101
20	Hydro	Iron Gate	Hornbrook, California	20.0	111,186
21	Hydro	Ashton	Ashton, Idaho	7.3	37,502
22	Hydro	Cove	Grace, Idaho	6.9	12,528
23	Hydro	Grace	Grace, Idaho	32.8	89,101
24	Hydro	Last Chance	Grace, Idaho	1.4	3,801
25	Hydro	Oneida	Preston, Idaho	23.1	37,517
26	Hydro	Paris	Paris, Idaho	0.8	2,548
27	Hydro	Soda	Soda, Idaho	7.3	14,435
28	Hydro	St. Anthony	St. Anthony, Idaho	0.5	1,989
29	Hydro	Bigfork	Bigfork, Montana	4.0	19,644
30	Hydro	Bend	Bend, Oregon	1.0	4,422
31	Hydro	Clearwater #1	Toketee Falls, Oregon	15.0	52,422
32	Hydro	Clearwater #2	Toketee Falls, Oregon	22.0	64,293
33	Hydro	Cline Falls	Redmond, Oregon	1.0	2,344
34	Hydro	Eagle Point	Eagle Point, Oregon	2.8	14,249
35	Hydro	East Side	Klamath Falls, Oregon	3.2	17,208
36	Hydro	Fish Creek	Toketee Falls, Oregon	12.0	61,662
37	Hydro	John C. Boyle	Keno, Oregon	82.0	295,918
38	Hydro	Lemolo #1	Toketee Falls, Oregon	29.0	136,933
39	Hydro	Lemolo #2	Toketee Falls, Oregon	35.0	164,674
40	Hydro	Powerdale	Hood River, Oregon	6.0	37,931
41	Hydro	Prospect #1	Prospect, Oregon	4.0	27,918
42	Hydro	Prospect #2	Prospect, Oregon	36.0	231,370
43	Hydro	Prospect #3	Prospect, Oregon	7.0	29,714
44	Hydro	Prospect #4	Prospect, Oregon	1.0	5,496
45	Hydro	Slide Creek	Toketee Falls, Oregon	18.0	99,229
46	Hydro	Soda Springs	Toketee Falls, Oregon	12.0	70,339
47	Hydro	Stayton	Stayton, Oregon	0.6	914
48	Hydro	Toketee	Toketee Falls, Oregon	42.0	238,947
49	Hydro	Wallowa Falls	Joseph, Oregon	1.0	2,057
50	Hydro	West Side	Klamath Falls, Oregon	1.0	3,252
51	Hydro	American Fork	Plesant Grove, Utah	0.9	1,649
52	Hydro	Beaver - Upper	Beaver, Utah	2.3	10,990

Sch. 35	SOURCES OF ELECTRIC SUPPLY				
	Type	**Plant Name**	**Location**	**Annual Peak - MW**	**Annual Energy - MWH**
53	Hydro	Cutler	Collinston, Utah	29.8	87,467
54	Hydro	Fountain Green	Fountain Green, Utah	0.2	1,[illegible]
55	Hydro	Granite	Salt Lake City, Utah	0.0	4,[illegible]
56	Hydro	Gunlock	Gunlock, Utah	0.6	2,351
57	Hydro	Olmsted	Orem, Utah	8.4	30,455
58	Hydro	Pioneer	Ogden, Utah	5.0	15,869
59	Hydro	Sand Cove	Sand Cove, Utah	0.6	1,679
60	Hydro	Snake Creek	Midway, Utah	1.4	3,180
61	Hydro	Stairs	Salt Lake City, Utah	1.2	5,613
62	Hydro	Veyo	Veyo, Utah	0.3	1,242
63	Hydro	Weber	Uintah, Utah	3.3	19,252
64	Hydro	Condit	Underwood, Washington	15.0	71,269
65	Hydro	Drop	Naches, Washington	1.2	4,566
66	Hydro	Merwin	Ariel, Washington	143.0	407,429
67	Hydro	Naches	Naches, Washington	4.5	10,716
68	Hydro	Swift #1	Cougar, Washington	240.0	499,047
69	Hydro	Yale	Amboy, Washington	134.0	446,048
70	Hydro	Viva Naughton	Kemmerer, Wyoming	0.7	2,023
71	Pumping	Lifton	Lifton, Idaho		(821)
72					
73		Total Net Generation			52,322,141
74					
75	**POWER PURCHASES - ACCOUNT 555**				
76					
77	Anaheim, City of		(1)		7,[illegible]8
78	Arizona Public Serice Company		10-31-2020		144,[illegible]1
79	Arizona Public Serice Company		(1)		67,321
80	Ashland, City of		(2)		1,717
81	BMT Geneva				4
82	Beaver City		(3)		55
83	Bell Mountain Power		1-2-2020		1,263
84	Biomass One, Limited Partnership		1-31-2010		175,064
85	Birch Creek Hydro		8-21-2019		9,188
86	Black Hills Power & Light Company		6-30-2012		1,653
87	Blanding City		(3)		553
88	Bogus Creek		12-31-2017		1,288
89	Boise Cascade Corporation		(1)		5
90	Bonneville Power Administration		(1)		951,088
91	Boston Power		12-31-2004		288
92	Boyd, James		12-31-2003		2,547
93	CDM Hydro		12-4-2019		34,343
94	California Dept. of Water Resources		(1)		57,439
95	Central Oregon Irrigation District		12-31-2018		18,898
96	Champion International Corp.		6-30-1994		29,648
97	Chelan County Public Utility Dist. No. 1		8-31-2018		268,975
98	Chelan County Public Utility Dist. No. 1		(1)		18,060
99	Colockum Transmission Company		(1)		2,297
100	Colorado Public Service Company		(1)		14[illegible]4
101	Columbia Storage Power Exchange		3-31-2003		25[illegible]43
102	Commercial Energy Management Co.		5-5-2020		1,524
103	Cook Electric		12-31-2017		10,178
104	Coos Curry Electric Cooperative		(3)		50

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak – MW	Annual Energy – MWH
105	Curtiss Livestock		12-31-1993		153
106	DAW Forest Products Company		(1)		1,528
107	Deer Creek Water Control District		(1)		5,155
108	Deseret Generation & Trans. Coop.		12-31-1997		511,461
109	Deseret Generation & Trans. Coop.		(1)		133,725
110	Difani, Chris		4-30-2007		85
111	Douglas County Public Utility Dist. No. 1		8-31-2018		241,615
112	Douglas County Public Utility Dist. No. 1		(1)		19,750
113	DR Johnson Lumber Company		12-31-2006		63,201
114	El Paso Electric Company		(1)		17,630
115	Eugene Water & Electric Board		(1)		2,897
116	Falls Creek		12-31-2019		15,357
117	Farmers Irrigation #2		12-31-2010		15,906
118	Fery, Lloyd		12-31-1993		284
119	Fillmore City		(3)		91
120	Fox, Marian		(3)		7
121	Galesville Dam		12-31-2021		5,263
122	General Chemical Company		(1)		4,326
123	Georgetown Power		7-2-2019		2,050
124	Grand Valley Rural Power Lines		(3)		120
125	Grant County Public Utility Dist. No. 2		(4)		87,600
126	Grant County Public Utility Dist. No. 2		10-31-2005		526,324
127	Grant County Public Utility Dist. No. 2		10-31-2005		748,886
128	Grant County Public Utility Dist. No. 2		(1)		49,773
129	Idaho Falls, City of		11-2-2023		42,438
130	Idaho Power Company		(1)		100,566
131	Ingram Warm Springs Ranch		5-31-2021		3,811
132	Intermountain Power Project		6-15-2027		362,015
133	Lacomb Hydro		12-31-2018		3,804
134	Lagoon Corporation		12-31-1993		208
135	Lake Siskiyou		12-31-2020		19,601
136	Los Alamos County Utility Department		(1)		390
137	Los Angeles, City of		(1)		44,258
138	Luckey, Paul		12-31-2013		334
139	Marsh Valley Hydro Electric Company		3-10-2028		3,246
140	Middlefork Irrigation District		12-31-2004		19,617
141	Mink Creek Hydro		12-31-2021		9,363
142	Montana Power Company		12-31-1995		87,600
143	Montana Power Company		(1)		43,072
144	Morgan City		(3)		20
145	Mountain Energy		12-31-2004		162
146	Murray City		(3)		212
147	Nephi City		(3)		18
148	Nevada Power Company		(1)		28,556
149	New Mexico Public Service Company		(1)		306,779
150	Nichols Gap		12-31-2021		2,428
151	Nicholson Sunnybar Ranch		6-27-2020		2,445
152	North Fork Sprague		12-31-2023		2,143
153	Odell Creek		12-31-2010		121
154	Opal Springs		12-31-2020		32,198
155	Ormsby, Leslie		12-31-1993		17
156	O. J. Power Company		3-4-2021		782

Sch. 35 SOURCES OF ELECTRIC SUPPLY

	Plant Type Name	Location	Annual Peak - MW	Annual Energy - MWH
157	Pacific Gas & Electric Company	(1)		249,742
158	Pancheri, Inc.	3-1-2013		171
159	Plains Electric	(1)		4,[illegible]
160	Platte River Power Authority	(1)		5,215
161	PLM, Inc.	12-31-2013		210
162	Portland General Electric Company	12-18-2001		24,000
163	Portland General Electric Company	(1)		1,375
164	Preston City Hydro	2-24-2017		3,237
165	Provo City	(3)		243
166	Provo City	(1)		7,222
167	Puget Sound Power & Light Company	(1)		105,135
168	Rocky Mountain Generation Cooperative	(1)		267,246
169	Rocky Mountain Generation Cooperative			222,463
170	Rousch, Neil	12-31-1993		407
171	SF Phosphates Limited	(1)		2,919
172	Sacramento Municipal Utility District	(1)		9,100
173	Salt River Project	(1)		139,017
174	San Diego Gas & Electric	(1)		48,576
175	Santiam Water Control District	12-31-2019		1,454
176	Seattle City Light	(1)		17,264
177	Sierra Pacific Power Company	(1)		559
178	Slate Creek	12-31-2018		12,967
179	Southern California Edison Company	(1)		132,697
180	Southern California Edison Company	3-15-2003		1,440
181	Southern California Edison Company			79,156
182	Southwestern Public Service Company	(1)		65,[illegible]
183	Spanish Fork City	(3)		44
184	Springville City	(3)		44
185	Strawberry Electric Service District	(1)		86
186	Sunnyside	2-3-2023		193,220
187	Tacoma City Light	(1)		2,448
188	Teton Generation Station	2-2-2020		598
189	Thayn Ranch Hydro	12-31-2015		1,740
190	TKO	1-1-2013		266
191	Tri-State Generation & Transmission	12-31-2020		850,162
192	Tucson Electric Power Company	(1)		94,717
193	Tucson Electric Power Company			15,600
194	United States Bureau of Reclamation	10-6-2000		15,406
195	United States Bureau of Reclamation	(1)		15,162
196	Utah Assoc. Municipal Power Systems	(1)		36,624
197	Utah Municipal Power Agency	(1)		1,253
198	Walla Walla, City of	12-31-2012		14,445
199	Warm Springs Forest Products Industry	(1)		564
200	Warm Spring Power Enterprises	12-31-2001		79,180
201	Washington Public Power Supply System	6-30-1996		586,151
202	Washington Water Power Company	12-31-1995		438,000
203	Washington Water Power Company	12-31-1995		20,100
204	Washington Water Power Company	(1)		175,[illegible]3
205	Western Area Power Administration	(1)		1[illegible]9
206	Westinghouse	12-15-2022		5,782
207	White, J. E.	12-31-2017		1,053

Sch. 35 SOURCES OF ELECTRIC SUPPLY

Line	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
208	Whitefish, City of				453
209	Whitmore Oxygen		(1)		1,593
210	Whitney, A. C.		None		1
211	Wiggins, Duane		12-31-1993		23
212	Yakima Tieton		12-31-2005		7,104
215		Total Power Purchases			9,745,834
217		Net Exchanges			297,376
219		Transmission by Others Losses			(370,386)
221		Total Sources			61,994,965

225 Notes:

226 (1) Non-firm.

227 (2) City of Ashland - Contract Termination Date: Upon 30 days written notice.

228 (3) Under electric service agreement subject to termination upon timely notification.

229 (4) Grant County Public Utility District #2 - Contract Termination Date: Upon 2 years written notice.

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Blundell								
1.	01/05/93	06:47	-	01/05/93	07:28	Forced	0.68	15.71
	Descr:	UNIT TRIPPED DURING ROUTINE ON LINE EMERGENCY OVERSPEED TESTCAUSED BY						
2.	01/05/93	07:28	-	04/02/93	22:12	Forced	2,102.73	48,362.81
	Descr:	UNIT TRIPPED AT 4015 RPM DURING OFF LINE EMERGENCY OVERSPEED TEST.						
3.	04/03/93	11:55	-	04/03/93	12:31	Maint.	0.60	13.80
	Descr:	UNIT OFF LINE TO PERFORM OFF LINE OVERSPEED TRIP TEST						
4.	05/16/93	20:25	-	05/16/93	21:25	Forced	1.00	23.00
	Descr:	TRANSMISSION LINE TRIP; LIGHTNING STORM						
5.	05/16/93	21:25	-	05/17/93	02:45	Forced	5.33	122.66
	Descr:	NCGR - AFTERCONDENSER RUPTURE DISK FAILED AFTER LIGHTNING STRIKE						
6.	07/09/93	17:33	-	07/09/93	17:55	Forced	0.37	8.42
	Descr:	UNIT RUN BACK; CAUSE UNKNOWN						
7.	08/06/93	20:29	-	08/06/93	20:39	Forced	0.17	3.82
	Descr:	46KV LINE TRIP; RUN BACK						
8.	09/16/93	04:32	-	09/17/93	01:17	Forced	20.75	477.25
	Descr:	UNIT OFF; TRANSMISSION LINE AND PLANT MAINTENANCE WORK						
9.	09/17/93	05:04	-	09/17/93	05:14	Forced	0.17	3.82
	Descr:	OCB21 TRIP/SIGURD SWITCHING ISOLATED BLUNDELL						
10.	09/17/93	05:46	-	09/17/93	05:56	Forced	0.17	3.82
	Descr:	OCB21 TRIPPED/SIGURD SWITCHING ISOLATED BLUNDELL						
11.	11/24/93	08:30	-	11/24/93	14:18	Forced	5.80	133.40
	Descr:	SURGE TANK LEVEL FROZE, OVERFILLED SURGE TANK AND SPILLED WATER INTO						
12.	11/24/93	14:25	-	11/24/93	14:52	Forced	0.45	10.35
	Descr:	UNIT TRIPPED; EXCESSIVE WATER IN STEAM						
13.	11/24/93	19:38	-	11/25/93	00:15	Forced	4.62	106.17
	Descr:	UNIT TRIPPED; EXCESSIVE WATER IN STEAM						
	*** * * Unit Summary for Blundell for the year 1993 =**						2,142.84	49,285.03
Carbon #1								
1.	02/18/93	14:38	-	02/18/93	16:53	Forced	2.25	153.00
	Descr:	UNI TRIP DUE O RELAY DEPARTMENT WORKING ON THE 138 KV BUS						
2.	02/19/93	15:29	-	02/21/93	09:54	Forced	42.42	2,884.29
	Descr:	DC BATTERY CHARGERS (BOTH) FAILED TO OPERATE						
3.	02/22/93	14:58	-	02/22/93	17:01	Forced	2.05	139.40
	Descr:	UNI TRIP - OPERATOR ERROR ON THE 125 V DC SYSTEM						
4.	04/05/93	17:49	-	04/07/93	11:20	Forced	41.52	2,823.09
	Descr:	ECONONMIZER TUBE LEAK (LOST UNIT ON FURNACE DRAFT). ALSO FOUND TUBE LE						
5.	04/24/93	20:59	-	04/24/93	23:00	Forced	2.02	137.09
	Descr:	UNIT TRIP - LOW DRUM LEVEL (CAUSE UNKNOWN - POSSIBLE INSTRUMENT PROBLE						
6.	04/26/93	00:11	-	05/07/93	08:30	Forced	272.32	18,517.49
	Descr:	STARTED EXPERIENCING HIGH VIBRATION THAT OCCURED INSTEP CHANGES. OPENE						
7.	05/23/93	10:12	-	05/24/93	06:56	Forced	20.73	1,409.84
	Descr:	ECONOMIZER TUBE LEAK (PREVIOUS REPAIR - BAD WELD)						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Carbon #1								
8.	07/30/93	17:49	-	08/02/93	00:50	Forced	55.02	3,741.09
	Descr:	ECONOMIZER TUBE LEAK DUE TO SOOTBLOWER EROSION						
9.	08/19/93	12:46	-	08/19/93	13:31	Forced	0.75	51.00
	Descr:	FEEDERS WEREPLUGGED WITH WET COAL - DOWN TO ONE MILL OPERATION AND FEE						
10.	09/24/93	18:21	-	09/26/93	13:06	Forced	42.75	2,907.00
	Descr:	ECONOMIZER TUBE LEAK - PREVIOUS REPAIR FAILED (WELD)						
11.	10/05/93	07:56	-	10/05/93	08:20	Forced	0.40	27.20
	Descr:	UNIT TRIP WHILE SWITCHING FROM 1-2 TO 1-1 BOILER FEED PUMP. 1-1 BOILE						
		*** * * Unit Summary for Carbon #1 for the year 1993 =**					482.23	32,790.49
Carbon #2								
1.	01/09/93	18:29	-	01/09/93	20:48	Forced	2.32	243.18
	Descr:	THERE APPEARED TO BE A LEAK IN THE MAIN STEAM LINE, BUT THE LEAK WAS						
2.	01/26/93	00:00	-	01/28/93	01:30	Forced	49.50	5,197.50
	Descr:	TUBE LEAK IN REHEAT SECTION. ALSO PAD WELDED MORE TUBES IN THE SAME AR						
3.	01/28/93	01:30	-	01/29/93	12:03	Forced	34.55	3,627.75
	Descr:	UNIT REMAINED OFF LINE AFTER REPAIR OF THE REHEAT TUBE DUE TO ANOTHER						
4.	02/01/93	07:51	-	02/01/93	08:42	Forced	0.85	89.25
	Descr:	MAX 1 CONTROL PROBLEM - IMPROPER OPERATIONAL PROCEDURE. I & C CORRECTE						
5.	02/09/93	14:07	-	02/09/93	16:34	Forced	2.45	257.25
	Descr:	RELAY DEPARTMENT WORKING IN CABINETS IN CONTROL ROOM AND THEY BUMPED T						
6.	02/18/93	14:38	-	02/18/93	15:56	Forced	1.30	136.50
	Descr:	UNIT TRIP - RELAY DEPARTMENT WAS WORKING ON THE 138 BUS						
7.	02/18/93	18:45	-	02/18/93	22:28	Forced	3.72	390.18
	Descr:	ON MAIN TRANSFORMER FIRE PROTECTION DELUGE SYTEM WAS ACTIVATED (DIA						
8.	04/08/93	01:06	-	04/09/93	09:17	Forced	32.18	3,379.22
	Descr:	ECONOMIZER TUBE LEAK. ALSO SPENT TIME CLEANING OUT THE BOILER DUE TO L						
9.	04/22/93	22:58	-	04/24/93	15:05	Forced	40.12	4,212.18
	Descr:	WATERWALL TUBE LEAK (INTERAL DEPOSIT ON THE TUBE)						
10.	06/08/93	21:06	-	06/10/93	04:37	Forced	31.52	3,309.18
	Descr:	ECONOMIZER TUBE LEAK						
11.	06/11/93	23:52	-	06/15/93	06:23	Forced	78.52	8,244.18
	Descr:	HIGH TEMPERATURE SUPERHEATER TUBE LEAK,HIGH TEMPERATURE CREEP						
12.	12/24/93	01:59	-	12/24/93	06:01	Forced	4.03	423.47
	Descr:	UNIT TRIPPED WHEN A WASH DOWN LINE THAT WAS LEFT PRESSURIZED RUPTURED						
		*** * * Unit Summary for Carbon #2 for the year 1993 =**					281.06	29,509.84
Centralia #1								
1.	04/30/93	22:22	-	05/02/93	10:45	Forced	36.38	23,830.87
	Descr:	REPAIR #11 BOILER FEEDPUMP SENSING LINE.						
2.	05/02/93	11:37	-	05/31/93	04:53	Forced	689.27	451,469.23
	Descr:	OPERATOR ERROR - GENERATOR OVERHEATING ALARM						
3.	06/01/93	08:00	-	06/10/93	03:30	Forced	211.50	138,532.50
	Descr:	UNSATISFACTORY GENERATOR AIR TEST						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Centralia #1								
4.	06/14/93	13:47	-	06/15/93	03:12	Forced	13.42	8,787.48
	Descr:	ELECTRICAL FAILURE-'C' PHASE C.T. LEAD INSULATION FAILED. SHORTED TO G						
5.	06/17/93	12:07	-	06/17/93	20:46	Forced	8.65	5,665.75
	Descr:	SHUT DOWN TO PROVIDE ELECTRICAL PROTECTION WHILE SWAPPING OUT 500KV						
6.	06/27/93	13:06	-	06/30/93	17:02	Forced	75.93	49,736.12
	Descr:	ELECTRICAL FAILURE GENERATOR B-PHASE 287G DIFF. RELAY						
7.	07/02/93	19:56	-	07/03/93	01:39	Forced	5.72	3,743.98
	Descr:	REPLACE GENERATOR C.T. WIRING TERMINAL BLOCKS						
8.	07/09/93	15:09	-	07/11/93	00:34	Forced	33.42	21,887.48
	Descr:	TUBE LEAK						
9.	07/11/93	00:53	-	07/11/93	01:30	Forced	0.62	403.48
	Descr:	LOW VACUUM						
10.	08/14/93	20:20	-	08/17/93	13:47	Forced	65.45	42,869.75
	Descr:	BOILER TUBE LEAK #11 BA HOPPER						
11.	08/25/93	00:30	-	08/27/93	22:36	Forced	70.10	45,915.50
	Descr:	TUBE LEAK						
	*** * * Unit Summary for Centralia #1 for the year 1993 =**						1,210.46	792,842.14
Centralia #2								
1.	02/28/93	01:32	-	02/28/93	18:14	Forced	16.70	10,938.50
	Descr:	#21 BCP SUCTION VALVE PACKING BLEW OUT.						
2.	03/05/93	16:52	-	03/08/93	02:49	Forced	57.95	37,957.25
	Descr:	BOILER TUBE LEAK - SUPERHEATER STEAM COOLED WRAPPER TUBE.						
3.	03/08/93	19:38	-	03/10/93	20:12	Forced	48.57	31,810.73
	Descr:	REHEAT TUBE LEAKS.						
4.	03/27/93	00:02	-	03/27/93	13:57	Forced	13.92	9,114.98
	Descr:	FLANGE LEAK ON IP TURBINE COOLING STEAM LINE.						
5.	05/14/93	21:30	-	06/10/93	07:00	Planned	633.50	414,942.50
	Descr:	ANNUAL TURBINE OVERHAUL						
6.	06/10/93	07:00	-	06/15/93	15:00	Planned	128.00	83,840.00
	Descr:	PLANNED OUTAGE EXTENSION. BOILER WORK TAKING LONGER THAN PLANNED.						
7.	06/15/93	15:00	-	06/18/93	16:00	Planned	73.00	47,815.00
	Descr:	PLANNED (CHEMICAL CLEAN)						
8.	06/18/93	16:00	-	06/24/93	23:30	Forced	151.50	99,232.50
	Descr:	B-PHASE MAIN TRANSFORMER CHANGEOUT DUE TO LOST WASHER						
9.	06/24/93	23:30	-	06/28/93	17:48	Forced	90.30	59,146.50
	Descr:	REHEAT STOP VALVES STUCK						
10.	06/28/93	20:05	-	06/28/93	20:58	Planned	0.88	578.37
	Descr:	OVERHAUL TRIP TESTS.						
11.	06/29/93	01:25	-	06/29/93	02:21	Planned	0.93	611.12
	Descr:	MAIN TURBINE OVERSPEED TEST						
12.	06/29/93	22:55	-	06/30/93	05:18	Forced	6.38	4,180.87
	Descr:	BALANCE SHOTS						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Centralia #2								
13.	07/03/93	23:48	-	07/05/93	07:16	Forced	31.47	20,610.23
	Descr:	TUBE LEAK - FRONT SUPERHEAT PENDANT, SOUTH SIDE						
14.	07/29/93	23:50	-	08/01/93	00:00	Forced	48.17	31,548.73
	Descr:	GENERATOR SEALS REPAIR						
15.	08/01/93	00:00	-	08/10/93	04:21	Forced	220.35	144,329.25
	Descr:	GENERATOR SEALS REPAIR						
16.	08/17/93	17:44	-	08/20/93	05:45	Forced	60.02	39,310.48
	Descr:	TUBE LEAK REPAIR. FRONT RH PENDANT 'C' GROUP, CENTER OF BOILER						
17.	08/20/93	06:11	-	08/20/93	07:56	Forced	1.75	1,146.25
	Descr:	LOW BCP INJECTION WATER PRESSURE.						
18.	08/26/93	09:21	-	08/26/93	20:14	Forced	10.88	7,128.37
	Descr:	SHEETMETAL COVERING CONDENSATE SUCTION CAUSING CONDENSATE PUMPS TO CAV						
19.	10/19/93	00:14	-	10/21/93	09:28	Forced	57.23	37,487.62
	Descr:	WATERWALL TUBE LEAK AT THROAT SLOPE BELOW THE DIVISION WALL.						
20.	11/02/93	22:21	-	11/03/93	09:52	Forced	11.52	7,542.98
	Descr:	LEFT UPPER INTERCEPT VALVE REPAIR						
21.	12/07/93	15:57	-	12/07/93	18:27	Forced	2.50	1,637.50
	Descr:	AIR FLOW AND FURNACE PRESSURE PROBLEMS - #22 ID FAN EMA WOULD NOT OPER						
22.	12/07/93	18:27	-	12/09/93	07:20	Forced	36.88	24,158.37
	Descr:	TUBE LEAK, NORTH SECTION OF WATER COOLED SPACER TUBE TO SUPERHEAT PLAT						
23.	12/20/93	11:05	-	12/20/93	11:44	Forced	0.65	425.75
	Descr:	E-H POWER SUPPLY FAILURE						
		*** * * Unit Summary for Centralia #2 for the year 1993 =**					1,703.05	***,***.**
Cholla #4								
1.	01/08/93	08:39	-	01/08/93	10:27	Forced	1.80	630.00
	Descr:	I.R. CHANGING OUT RELAY, 125V TRIP ENERGIZED TRIPPING UNIT						
2.	01/08/93	11:44	-	01/08/93	12:39	Forced	0.92	320.60
	Descr:	"A" BOILER FEED PUMP REGULATOR MALFUNCTION						
3.	02/24/93	08:48	-	02/24/93	13:17	Forced	4.48	1,569.05
	Descr:	#1 BEARING HIGH VIBRATION, FALSE INDICATION, STARTUP DELAYED DUE TO						
4.	02/27/93	22:28	-	03/01/93	12:14	Forced	37.77	13,218.10
	Descr:	OFF LINE TO REPAIR A WATERWALL TUBE LEAK						
5.	03/01/93	13:33	-	03/01/93	14:25	Forced	0.87	303.10
	Descr:	HIGH DRUM LEVEL						
6.	03/01/93	15:27	-	03/01/93	16:23	Forced	0.93	326.55
	Descr:	HIGH DRUM LEVEL						
7.	03/01/93	18:03	-	03/01/93	20:57	Forced	2.90	1,015.00
	Descr:	HIGH DRUM LEVEL						
8.	03/19/93	19:51	-	03/21/93	06:01	Forced	34.17	11,958.10
	Descr:	WATERWALL TUBE LEAK						
9.	03/21/93	13:48	-	03/25/93	09:15	Forced	91.45	32,007.50
	Descr:	WATERWALL TUBE LEAK						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Cholla #4								
10.	04/02/93	17:56	-	04/03/93	15:18	Maint.	21.37	7,478.10
	Descr: WATERWALL TUBE LEAK REPAIRS							
11.	05/12/93	09:19	-	05/12/93	11:21	Forced	2.03	711.55
	Descr: BOILER FEED PUMP CONTROLS VIBRATION TRIP							
12.	05/12/93	12:03	-	05/12/93	13:10	Forced	1.12	390.60
	Descr: DISCHARGE VALVE FAILURE							
13.	05/21/93	23:01	-	06/01/93	00:00	Planned	240.98	84,344.05
	Descr: MINOR OVERHAUL							
14.	06/01/93	00:00	-	06/08/93	12:36	Planned	180.60	63,210.00
	Descr: MINOR OVERHAUL							
15.	11/23/93	14:31	-	11/23/93	15:53	Forced	1.37	478.10
	Descr: FD FAN CONTROLS MALFUNCTION							
16.	12/29/93	07:49	-	12/29/93	11:51	Forced	4.03	1,411.55
	Descr: TSI SIGNAL INTERRUPTED DURING MONTHLY TURBINE VIBRATION READS							
17.	12/29/93	12:17	-	12/29/93	15:59	Forced	3.70	1,295.00
	Descr: FEEDWATER UPSET HIGH DRUM LEVEL							
18.	12/29/93	16:37	-	12/29/93	17:31	Forced	0.90	315.00
	Descr: FEEDWATER UPSET HIGH DRUM LEVEL							
	*** * * Unit Summary for Cholla #4 for the year 1993 =**						631.39	220,981.95
Dave Johnston #1								
1.	03/23/93	02:40	-	03/23/93	04:10	Forced	1.50	157.50
	Descr: DRAFT TRIP							
2.	03/23/93	07:01	-	03/23/93	08:34	Forced	1.55	162.75
	Descr: FAULTY TURBINE VACUUM TRIP DEVICE							
3.	05/29/93	02:33	-	06/18/93	20:50	Planned	498.28	52,319.72
	Descr: UNIT OVERHAUL							
4.	09/27/93	09:44	-	09/27/93	14:03	Forced	4.32	453.18
	Descr: NET 90 TROUBLE - LOADING NEW CONFIG'S FROM EWS							
5.	10/14/93	12:52	-	10/15/93	06:41	Forced	17.82	1,870.68
	Descr: CONDENSER FOULING - LOW VAC							
6.	10/15/93	06:41	-	10/15/93	07:12	Forced	0.52	54.18
	Descr: NEAR NEUTRAL GROUND ALARM							
7.	10/15/93	11:01	-	10/15/93	18:02	Forced	7.02	736.68
	Descr: LEAK ON REHEAT SPRAY LINE							
	*** * * Unit Summary for Dave Johnston #1 for the year 1993 =**						531.01	55,754.69
Dave Johnston #2								
1.	02/28/93	19:03	-	03/01/93	16:00	Forced	20.95	2,199.75
	Descr: BOILER TUBE LEAK							
2.	03/01/93	16:00	-	03/03/93	00:50	Forced	32.83	3,447.47
	Descr: NO CONDENSATE TO START UNIT.							
3.	06/16/93	14:06	-	06/18/93	17:42	Forced	51.60	5,418.00
	Descr: ROOF TUBE LEAK							

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #2								
4.	11/04/93	15:53	-	11/04/93	16:54	Forced	1.02	106.68
	Descr: FD FAN CTL TROUBLE AT HALF LOAD							
	*** Unit Summary for Dave Johnston #2 for the year 1993 =						106.40	11,171.90
Dave Johnston #3								
1.	01/15/93	03:25	-	01/17/93	08:51	Forced	53.43	11,755.26
	Descr: BOILER TUBE LEAK							
2.	02/17/93	08:40	-	02/20/93	18:35	Forced	81.92	18,021.52
	Descr: BOILER WATERWALL LEAK							
3.	05/16/93	01:14	-	05/17/93	00:15	Forced	23.02	5,063.52
	Descr: WATER WALL TUBE LEAK							
4.	05/17/93	00:15	-	05/17/93	07:35	Forced	7.33	1,613.26
	Descr: IGNITOR TROUBLE START UP DELAY							
5.	06/21/93	03:57	-	06/21/93	05:17	Forced	1.33	293.26
	Descr: MFT & TURB TRIP ON HI DRUM LEVEL FEEDER PLUGGED W/LARGE COAL							
6.	06/21/93	13:40	-	06/21/93	14:29	Forced	0.82	179.52
	Descr: FEEDERS PLUGGED W/ LARGE COAL							
7.	06/21/93	14:40	-	06/21/93	16:30	Forced	1.83	403.26
	Descr: FEEDERS PLUGGED W/LARGE COAL							
8.	06/26/93	16:40	-	06/26/93	17:16	Forced	0.60	132.00
	Descr: FEEDERS PLUGGED W/ LARGE COAL							
9.	06/26/93	18:19	-	06/26/93	18:57	Forced	0.63	139.26
	Descr: LOST VACUUM							
10.	06/28/93	09:38	-	06/28/93	11:02	Forced	1.40	308.00
	Descr: FEEDER PLUGGED W/LARGE COAL: TRIPPED UNIT ON HIGH DRUM LEVEL							
11.	08/15/93	04:24	-	08/16/93	01:34	Forced	21.17	4,656.52
	Descr: CABLE FAILURE TO 3B FD FAN (REPAIR)							
12.	09/28/93	02:16	-	09/28/93	03:35	Forced	1.32	289.52
	Descr: MAINT. PROCEDURE ERROR - C&ET CLEANING MFT CBT W/ AIR & TRIPPED RELAY							
13.	11/30/93	08:10	-	11/30/93	19:47	Forced	11.62	2,555.52
	Descr: FAILED THERMAL WELL CAUSED MAIN STEAM LINE LEAK							
	*** Unit Summary for Dave Johnston #3 for the year 1993 =						206.42	45,410.42
Dave Johnston #4								
1.	01/07/93	08:59	-	01/13/93	12:00	Forced	147.02	47,045.12
	Descr: GENERATOR ROTOR GROUND							
2.	01/13/93	12:00	-	02/25/93	00:01	Planned	1,020.02	326,405.12
	Descr: TURBINE/BOILER OVERHAUL							
3.	02/25/93	00:01	-	02/26/93	21:24	Forced	45.38	14,522.56
	Descr: GENERATOR ROTOR GROUND							
4.	02/26/93	22:54	-	03/01/93	00:55	Forced	50.02	16,005.12
	Descr: HI BEARING VIBRATION ON TURBINE							
5.	03/01/93	04:27	-	03/01/93	13:07	Forced	8.67	2,773.12
	Descr: FEEDWATER VALVE PACKING							

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #4								
6.	03/01/93	13:07	-	03/01/93	19:59	Forced	6.87	2,197.12
	Descr:	NO CONDENSATE FOR START-UP.						
7.	03/02/93	06:14	-	03/02/93	12:47	Forced	6.55	2,096.00
	Descr:	MFT DUE TO THRUST BIG TRIP OUT						
8.	03/02/93	13:05	-	03/02/93	13:58	Forced	0.88	282.56
	Descr:	FLAME OUT						
9.	03/02/93	14:55	-	03/02/93	15:45	Forced	0.83	266.56
	Descr:	HIGH DRUM LEVEL TRIP						
10.	03/02/93	17:02	-	03/02/93	17:35	Forced	0.55	176.00
	Descr:	FLAME OUT						
11.	03/06/93	01:20	-	03/07/93	22:09	Maint.	44.82	14,341.12
	Descr:	TURBINE BEARING WORK						
12.	04/09/93	19:54	-	04/09/93	22:02	Forced	2.13	682.56
	Descr:	4A PA FAN INST. TRIP						
13.	04/09/93	22:02	-	04/10/93	01:20	Forced	3.30	1,056.00
	Descr:	#2 BRNG VIB. 12 MILS						
14.	04/10/93	01:28	-	04/10/93	02:49	Forced	1.35	432.00
	Descr:	#2 BRNG 12MILS VIBR.						
15.	05/18/93	00:56	-	05/21/93	05:03	Forced	76.12	24,357.12
	Descr:	MFT REPAIR TUBE LEAK						
16.	05/24/93	01:43	-	05/24/93	03:38	Forced	1.92	613.12
	Descr:	MFT DRUM LEVEL HIGH						
17.	06/18/93	07:38	-	06/18/93	09:08	Forced	1.50	480.00
	Descr:	3A CRSHR MTR GROUNDED TRIPPED 4A PA FAN						
18.	07/10/93	03:14	-	07/11/93	16:17	Forced	37.05	11,856.00
	Descr:	MFT BRINGING UNIT DOWN TO DESLAG BOILER						
19.	08/22/93	19:05	-	08/25/93	12:26	Forced	65.35	20,912.00
	Descr:	SCRUBBER 4160 TRFMR FAILURE -REPLACING CABLE & TRANSFORMER						
20.	08/30/93	16:49	-	08/30/93	19:10	Forced	2.35	752.00
	Descr:	THRUST BRG WEAR DETECTOR TEST MALFUNCTION						
21.	11/03/93	08:15	-	11/04/93	02:51	Forced	18.60	5,952.00
	Descr:	WATER SPRAYED ON CT X-FMR GROUNDED OUT						
22.	11/05/93	16:55	-	11/07/93	21:40	Maint.	52.75	16,880.00
	Descr:	FIX TUBE LEAK & MISC. MAINT.						
23.	11/09/93	09:36	-	11/09/93	10:46	Forced	1.17	373.12
	Descr:	"B" ID FAN CONTROL TROUBLE						
24.	12/10/93	02:29	-	12/10/93	03:25	Forced	0.93	298.56
	Descr:	OUTAGE FOR TUBE LEAK REPAIRS						
25.	12/10/93	23:30	-	12/15/93	01:38	Maint.	98.13	31,402.56
	Descr:	OUTAGE FOR TUBE LEAK REPAIRS						
	*** * * Unit Summary for Dave Johnston #4 for the year 1993 =**						1,694.26	542,157.44

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Gadsby #3								
1.	01/05/93	02:20	-	01/05/93	07:20	Forced	5.00	500.00
	Descr: NEEDED TO REVERSE POLARITY ON EXCITOR. EQUIPMENT WAS NOT FUNCTIONING.							
2.	02/08/93	11:05	-	02/12/93	18:22	Forced	103.28	10,328.30
	Descr: #1 TURBINE BEARING WAS EXPERIENCING HIGH VIBRATION DUE TO BEARING FAIL							
3.	02/12/93	23:21	-	02/12/93	23:38	Forced	0.28	28.30
	Descr: #3 UNIT OVERSPEED TEST							
4.	02/13/93	13:58	-	02/14/93	04:38	Forced	14.67	1,466.60
	Descr: 3-2 CONDENSATE HOTWELL PUMP WAS SPRAYED WITH WATER AND TRIPPED. THE CO							
5.	03/27/93	13:14	-	03/27/93	16:50	Forced	3.60	360.00
	Descr: SIGHT GLASS BROKE ALLOWING OIL AND HYDROGEN GAS INTO THE ATMOSPHERE CA							
6.	04/11/93	07:51	-	04/11/93	10:41	Forced	2.83	283.30
	Descr: TESTING MAIN STEAM STOP VALVES. VALVE STUCK CAUSING UNIT TRIP.							
7.	04/16/93	10:43	-	04/16/93	12:26	Forced	1.72	171.60
	Descr: BAILEY WORKING OF CONTROLS. FURNACE PRESSURE WENT LOW CAUSING TRIP							
8.	06/12/93	23:07	-	06/13/93	08:00	Forced	8.88	888.30
	Descr: BOTTOM NORTH SIDE WATERWALL HEADER HANDHOLE WELD CRACKED							
9.	11/01/93	22:41	-	11/02/93	08:10	Forced	9.48	948.30
	Descr: U3 CONDENSOR TUBE LEAK							
10.	11/12/93	14:56	-	11/12/93	16:26	Forced	1.50	150.00
	Descr: SHUT OFF 1 OF 2 IGNITOR AIR FANS. SYSTEM SHOULD OPERATE ON 1 FAN BUT I							
11.	12/12/93	21:15	-	12/13/93	00:37	Forced	3.37	336.60
	Descr: LIMIT SWITCH SHOWED BURNER OPEN AND CLOSED AT THE SAME TIME CAUSING BO							
	*** Unit Summary for Gadsby #3 for the year 1993 =						154.61	15,461.30
Hunter #1								
1.	04/02/93	20:34	-	04/05/93	06:38	Maint.	57.07	22,541.07
	Descr: OFF LINE - THROTTLE VALVE REPAIR							
2.	04/05/93	07:22	-	04/05/93	11:22	Maint.	4.00	1,580.00
	Descr: OFF LINE - THROTTLE VALVE REPAIR							
3.	09/08/93	21:30	-	09/10/93	01:07	Forced	27.62	10,908.32
	Descr: BOILER TUBE LEAK (STEAM COOLED WALL)							
4.	10/03/93	23:00	-	10/08/93	08:55	Planned	105.92	41,836.82
	Descr: UNIT OUTAGE (BOILER)							
	*** Unit Summary for Hunter #1 for the year 1993 =						194.61	76,866.21
Hunter #2								
1.	02/03/93	15:40	-	02/04/93	01:15	Forced	9.58	3,785.29
	Descr: LOSS OF FLAME TRIP, ASH BRIDGE							
2.	05/20/93	15:23	-	05/24/93	05:18	Forced	85.92	33,936.82
	Descr: BOILER TUBE LEAK (ECONOMIZER)							
3.	06/11/93	17:52	-	06/13/93	05:55	Forced	36.05	14,239.75
	Descr: BOILER TUBE LEAK (ECONOMIZER)							
4.	06/13/93	08:58	-	06/14/93	05:46	Forced	20.80	8,216.00
	Descr: BOILER TUBE LEAK (STEAM COOLED WALL)							

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Hunter #2								
5.	06/23/93	23:00	-	06/24/93	21:44	Forced	22.73	8,979.54
	Descr:	BOILER TUBE LEAK (STEAM COOLED WALL)						
6.	07/02/93	15:56	-	07/03/93	23:42	Forced	31.77	12,547.57
	Descr:	BOILER TUBE LEAK						
7.	07/07/93	17:38	-	07/08/93	02:06	Forced	8.47	3,344.07
	Descr:	UNIT TRIP - DEH PROBLEM						
8.	10/01/93	07:58	-	10/01/93	10:30	Forced	2.53	1,000.54
	Descr:	UNIT TRIP-LOW DRUM LVL, BFPT TROUBLE						
9.	10/01/93	10:30	-	10/03/93	05:24	Forced	42.90	16,945.50
	Descr:	BOILER TUBE LEAK (REHEAT SECTION)						
10.	11/03/93	23:55	-	11/05/93	14:32	Forced	38.62	15,253.32
	Descr:	BOILER TUBE LEAK (REHEAT SECTION)						
11.	11/05/93	15:30	-	11/05/93	16:20	Forced	0.83	329.04
	Descr:	UNIT TRIP-FLAME FAILURE TRIP						
12.	12/04/93	06:09	-	12/05/93	16:51	Forced	34.70	13,706.50
	Descr:	OFF LINE - CONDENSER TUBE LEAK						
13.	12/10/93	06:35	-	12/11/93	20:03	Forced	37.47	14,799.07
	Descr:	BOILER TUBE LEAK (ECONOMIZER)						
	*** * * Unit Summary for Hunter #2 for the year 1993 =**						372.37	147,083.01
Hunter #3								
1.	01/04/93	13:35	-	01/04/93	17:24	Forced	3.82	1,507.32
	Descr:	ELECTRICIANS TRIPPED ID FANS						
2.	01/12/93	17:10	-	01/12/93	20:35	Forced	3.42	1,349.32
	Descr:	LOST BFPT 3-1, LOW DRUM LEVEL TRIP						
3.	03/06/93	01:03	-	04/13/93	02:01	Planned	911.97	360,226.57
	Descr:	MAJOR TURBINE OVERHAUL						
4.	04/13/93	09:14	-	04/14/93	21:52	Forced	36.63	14,470.04
	Descr:	TURBINE OVERSPEED TESTING						
5.	04/15/93	05:46	-	04/15/93	08:53	Forced	3.12	1,230.82
	Descr:	UNIT TRIPPED - 3-2 BFPT TRIPPED						
6.	04/15/93	16:34	-	04/15/93	20:57	Forced	4.38	1,731.29
	Descr:	UNIT TRIP - 3-2 BFPT TRIP						
7.	04/16/93	01:51	-	04/16/93	04:56	Forced	3.08	1,217.79
	Descr:	UNIT TRIP - 3-2 BFPT TRIP						
8.	04/18/93	01:06	-	04/18/93	03:21	Forced	2.25	888.75
	Descr:	UNIT TRIP, UPPER THRUST BEARING TEST						
9.	04/22/93	15:26	-	04/22/93	20:03	Forced	4.62	1,823.32
	Descr:	UNIT TRIPPED - EXCITER PROBLEMS						
10.	05/08/93	00:00	-	05/09/93	01:42	Maint.	25.70	10,151.50
	Descr:	UNIT OFF LINE TO BALANCE TURBINE						
11.	08/05/93	22:06	-	08/06/93	09:30	Forced	11.40	4,503.00
	Descr:	UNIT TRIP - 3-1 BFPT TRANSMITTER BAD						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Hunter #3								
12.	08/28/93	06:13	-	09/01/93	06:56	Forced	96.72	38,202.82
	Descr: UNIT OFF - BROKEN BLADE LP TURBINE							
13.	09/30/93	20:45	-	09/30/93	23:01	Forced	2.27	895.07
	Descr: UNIT TRIP - FURNACE DRAFT							
14.	10/01/93	00:13	-	10/01/93	02:16	Forced	2.05	809.75
	Descr: UNIT TRIP ON FURNACE DRAFT							
15.	12/24/93	10:03	-	12/24/93	18:55	Forced	8.87	3,502.07
	Descr: BOILER TRIP - HIGH FURNACE PRESSURE							
16.	12/31/93	18:23	-	01/01/94	00:00	Forced	5.62	2,218.32
	Descr: BOILER TRIP - FIRE ON BURNER FRONT							
	*** * * Unit Summary for Hunter #3 for the year 1993 =**						1,125.92	444,727.75
Huntington #1								
1.	01/08/93	21:02	-	01/08/93	23:43	Forced	2.68	1,073.20
	Descr: LOSS OF EHC PRESSURE WHILE DOING EHC PUMP AUTO STARTS.							
2.	02/03/93	04:00	-	02/03/93	07:58	Forced	3.97	1,586.40
	Descr: OUT OF ADJUSTMENT							
3.	02/03/93	09:04	-	02/03/93	16:01	Forced	6.95	2,780.00
	Descr: PLUGGAGE							
4.	02/09/93	11:01	-	02/10/93	01:42	Forced	14.68	5,873.20
	Descr: TUBE LEAK							
5.	04/13/93	02:51	-	04/13/93	06:35	Forced	3.73	1,493.20
	Descr: NOT READING CORRECTLY - I&C WENT TO WORK ON THEM - UNIT TRIPPED							
6.	08/07/93	02:13	-	08/07/93	03:06	Forced	0.88	353.20
	Descr: UNIT BENCH TEST IN PROGRESS							
7.	10/14/93	21:39	-	10/19/93	04:00	Planned	102.35	40,940.00
	Descr: OVERHAUL - SCRUBBER WORK							
8.	10/19/93	04:00	-	10/23/93	10:00	Planned	102.00	40,800.00
	Descr: GENERAL OVERHAUL - PRECIPITATOR WORK							
9.	10/23/93	10:00	-	11/08/93	11:46	Planned	386.77	154,706.40
	Descr: GENERAL OVERHAUL - BOILER WORK							
10.	11/08/93	12:30	-	11/08/93	19:22	Forced	6.87	2,746.40
	Descr: STARTUP FAILURE							
11.	11/10/93	04:53	-	11/10/93	06:02	Forced	1.15	459.60
	Descr: TRIP TEST							
12.	11/10/93	20:27	-	11/11/93	11:21	Forced	14.90	5,960.00
	Descr: TUBE LEAK							
13.	11/18/93	23:43	-	11/20/93	20:54	Forced	45.18	18,073.20
	Descr: SILICA							
	*** * * Unit Summary for Huntington #1 for the year 1993 =**						692.11	276,844.80

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Huntington #2								
1.	02/10/93	05:10	-	02/14/93	03:30	Maint.	94.33	38,204.87
	Descr:	TUBE LEAK						
2.	02/20/93	00:03	-	02/20/93	01:39	Forced	1.60	648.00
	Descr:	UNIT TRIPPED WHEN TESTED						
3.	03/09/93	22:42	-	03/10/93	12:40	Forced	13.97	5,656.23
	Descr:	TUBE LEAK						
4.	03/10/93	14:13	-	03/10/93	15:37	Forced	1.40	567.00
	Descr:	DID NOT CLOSE, ELECTRICAL PROBLEM						
5.	05/11/93	01:34	-	05/12/93	19:00	Forced	41.43	16,780.37
	Descr:	TUBE LEAK						
6.	05/12/93	19:00	-	05/13/93	07:21	Forced	12.35	5,001.75
	Descr:	WORN - IN NEED OF REPAIR						
7.	05/13/93	07:21	-	05/13/93	12:03	Forced	4.70	1,903.50
	Descr:	TUBE LEAK						
8.	05/13/93	15:45	-	05/13/93	16:10	Maint.	0.42	168.48
	Descr:	REMOVED UNIT FROM LINE FOR OVERSPEED TRIP TESTS						
9.	05/31/93	17:21	-	06/01/93	06:33	Forced	13.20	5,346.00
	Descr:	TUBE LEAK						
10.	11/09/93	00:02	-	11/09/93	20:24	Forced	20.37	8,248.23
	Descr:	FAILED						
11.	12/04/93	00:00	-	12/06/93	09:11	Planned	57.18	23,159.12
	Descr:	MINI-OVERHAUL						
	*** * * Unit Summary for Huntington #2 for the year 1993 =**						260.95	105,683.55
Jim Bridger #1								
1.	01/21/93	23:34	-	01/22/93	01:17	Forced	1.72	892.32
	Descr:	TRANSMISSION SYSTEM PROBLEMS. (RASA) BORAH LINE TRIPPED AS 2307 WOULD						
2.	01/31/93	11:35	-	01/31/93	12:35	Forced	1.00	520.00
	Descr:	MIDPOINT 500KV LINE RELAYED.						
3.	03/01/93	08:23	-	03/01/93	08:55	Forced	0.53	277.16
	Descr:	BCP DELTA P LOW. #11 BFP IN MANUAL. #12 BFP 100% IN AUTOMATIC. DRUM						
4.	03/06/93	20:54	-	03/07/93	23:54	Forced	27.00	14,040.00
	Descr:	OPERATOR INITIATED. BOILER SLAGGING CONDITIONS IN REHEATER. DESLAG R						
5.	04/30/93	07:02	-	05/02/93	01:57	Forced	42.92	22,316.32
	Descr:	OPERATOR TRIP-BOILER SUPERHEAT TUBE LEAK. SUPERHEAT PLATEN, PANEL #9,						
6.	05/02/93	06:18	-	05/02/93	07:08	Forced	0.83	433.16
	Descr:	UNIT TRIPPED PM A 500KV LINE TRANSFER TRIP AT MIDNIGHT.						
7.	05/09/93	04:23	-	05/09/93	04:55	Forced	0.53	277.16
	Descr:	LOSS OF BOTH P.A. FANS. SEVERE SLAG FALL APPARENTLY TRIPPED FANS DUE						
8.	05/09/93	05:55	-	05/09/93	06:30	Forced	0.58	303.16
	Descr:	TOTAL FLAME FAILURE-NO PROBLEM FOUND.						
9.	06/16/93	22:00	-	06/16/93	22:48	Forced	0.80	415.48
	Descr:	SWITCHYARD TRIP-TRIPPED BY DISPATCH. SWITCHYARD 500KV LINE. TRYING T						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #1								
10.	06/20/93	13:14	-	06/20/93	13:41	Forced	0.45	234.00
	Descr:	LOSS OF DA LEVEL CAUSING LOSS OF BFBP AND BFP. BFP WOULD NOT RESET.						
11.	06/20/93	13:58	-	06/20/93	14:17	Forced	0.32	164.32
	Descr:	LESS THAN TWO FEEDERS ESTABLISHED. WHEN WARM UP GUNS WERE RETRACTED M						
12.	06/27/93	00:37	-	06/27/93	20:30	Forced	19.88	10,339.16
	Descr:	CO USED REVERSE POWER INTERLOCK BUTTON AND OPENED GENERATOR BREAKERS.						
13.	06/27/93	20:30	-	06/28/93	10:21	Forced	13.85	7,202.00
	Descr:	#11 APH AUX. DRIVE COUPLING FAILED.						
14.	07/26/93	23:21	-	07/28/93	08:50	Forced	33.48	17,411.16
	Descr:	UNIT OFF FOR AIR PREHEATER REPAIRS.						
15.	07/28/93	08:50	-	07/29/93	15:00	Forced	30.17	15,686.32
	Descr:	AIR PREHEATER WASH.						
16.	07/29/93	15:00	-	07/29/93	17:37	Forced	2.62	1,360.32
	Descr:	BACK PRESSURE PROBLEMS DURING START UP.						
17.	08/09/93	11:25	-	08/10/93	16:52	Forced	29.45	15,314.00
	Descr:	UNIT OFF TO REPAIR SUPERHEAT TUBE LEAK.						
18.	09/05/93	15:34	-	09/08/93	06:01	Forced	62.45	32,474.00
	Descr:	PUSH BUTTON BY OPERATOR-RADIANT REHEAT TUBE LEAK.						
19.	09/08/93	07:43	-	09/08/93	11:51	Forced	4.13	2,149.16
	Descr:	IGNITORS-HAD 3 MILL IN OPERATION AND THEY WERE AT 90,000 LBS. C. O. T						
20.	09/11/93	00:22	-	09/11/93	01:30	Forced	1.13	589.16
	Descr:	SWITCHYARD TRIP-500KV LINE.						
21.	10/07/93	07:20	-	10/07/93	09:30	Forced	2.17	1,126.32
	Descr:	LOST UNIT ON HIGH STEAM TEMPERATURES DUE TO LACK OF BFP CONTROL.						
22.	10/07/93	09:30	-	10/07/93	11:17	Forced	1.78	927.16
	Descr:	STARTUP EXTENDED DUE TO PLUGGED MOISTURE SEPARATOR FOR IGNITOR AND WAR						
23.	10/27/93	13:19	-	10/29/93	04:30	Forced	39.18	20,375.16
	Descr:	UNIT OFF LINE TO DESLAG SH/RH.						
24.	10/29/93	04:30	-	10/29/93	08:50	Forced	4.33	2,253.16
	Descr:	CANNOT OPEN 10H330 FOR SWITCHING.						
25.	10/29/93	08:50	-	10/29/93	23:09	Forced	14.32	7,444.32
	Descr:	UNIT TO STAY OFF LINE-FINISHING SUPERHEATER TUBE LEAK.						
26.	11/01/93	16:01	-	11/02/93	20:42	Forced	28.68	14,915.16
	Descr:	UNIT OFF TO REPAIR LTSH TUBE LEAK.						
27.	12/11/93	23:52	-	12/13/93	05:20	Forced	29.47	15,322.32
	Descr:	OFF LINE - BOILER SLAGGING						
28.	12/13/93	05:20	-	12/13/93	16:23	Forced	11.05	5,746.00
	Descr:	REPAIR TUBE LEAK - WATER WALL						
29.	12/17/93	09:20	-	12/18/93	02:20	Forced	17.00	8,840.00
	Descr:	NORTH MAIN STEAM LINE INSPECTION PLUG LEAK						
30.	12/30/93	11:59	-	12/31/93	21:04	Forced	33.08	17,203.16
	Descr:	UNIT OFF TO REPAIR RH TUBE LEAKS (RAD RH)						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
	*** Unit Summary for Jim Bridger #1 for the year 1993 =						454.90	236,551.12
Jim Bridger #2								
1.	01/02/93	17:17	-	01/04/93	04:56	Forced	35.65	18,538.00
	Descr: UNIT OFF LINE TO REMOVE WINBOX PERF. PLATES TO CONDUCT BOILER TESTING							
2.	01/12/93	17:14	-	01/12/93	17:51	Forced	0.62	320.32
	Descr: DA LEVEL CONTROL VALVES MALFUNCTION. LOW BOILER CIRC. PUMP DELTA P.							
3.	03/27/93	14:57	-	03/28/93	13:13	Forced	22.27	11,578.32
	Descr: CONTROL OPERATOR USED TRIP BUTTON AT ZERO MW REHEAT TUBE LEAK IN PANEL							
4.	04/26/93	23:58	-	04/27/93	17:55	Forced	17.95	9,334.00
	Descr: PUSH BUTTON BY OPERATOR-BOILER TUBE LEAK. WATERWALL TUBE LEAK.							
5.	05/05/93	02:02	-	05/30/93	00:00	Planned	597.97	310,942.32
	Descr: UNIT OVERHAUL.							
6.	05/29/93	00:00	-	06/06/93	10:48	Planned	178.80	92,976.00
	Descr: EXTENDED PLANNED OUTAGE-GENERATOR STATOR WINDINGS.							
7.	06/06/93	14:27	-	06/06/93	16:41	Forced	2.23	1,161.16
	Descr: BALANCE SHOT.							
8.	06/14/93	08:44	-	06/14/93	10:44	Forced	2.00	1,040.00
	Descr: LOW BCP DELTA P. BOTH BFP'S TRIPPED. NO REASON HAS BEEN DEFINED. UN							
9.	06/21/93	20:05	-	06/21/93	21:25	Forced	1.33	693.16
	Descr: #22 BFPT TRIPPED AND WOULD NOT RESET FROM CONTROL ROOM. 22 BFPT WOULD							
10.	07/16/93	09:26	-	07/16/93	10:01	Forced	0.58	303.16
	Descr: 21 BFPT TRIP RESULTED IN UNIT TRIP (BCP DELTA P). 21 BFP TURBINE OVER							
11.	07/16/93	10:01	-	07/16/93	12:21	Forced	2.33	1,213.16
	Descr: P.A. FAN INLET VANE LINKAGE BROKEN.							
12.	09/29/93	12:11	-	10/01/93	20:00	Forced	55.82	29,024.32
	Descr: UNIT OFF LINE TO DESLAG BOILER.							
13.	10/01/93	20:00	-	10/02/93	12:18	Forced	16.30	8,476.00
	Descr: FEEDWATER PIPING-BUCKSTAY ON FEEDWATER LINE FELL OFF.							
14.	10/05/93	09:20	-	10/07/93	09:48	Forced	48.47	25,202.32
	Descr: UNIT OFF LINE TO REPAIR REHEATER TUBE LEAK.							
15.	12/02/93	10:35	-	12/03/93	06:03	Forced	19.47	10,122.32
	Descr: UNIT OFF TO REPAIR PHOSPHATE INJECTION LINE LEAK							
16.	12/03/93	06:03	-	12/03/93	09:27	Forced	3.40	1,768.00
	Descr: SWITCHING PROBLEMS - IN YARD							
	*** Unit Summary for Jim Bridger #2 for the year 1993 =						1,005.19	522,692.56
Jim Bridger #3								
1.	02/18/93	00:00	-	02/20/93	22:04	Forced	70.07	36,434.32
	Descr: DESLAG SH/RH.							
2.	02/26/93	14:40	-	02/26/93	19:02	Forced	4.37	2,270.32
	Descr: LOOSE WIRE IN FSSS.							
3.	04/12/93	03:31	-	04/13/93	20:21	Forced	40.83	21,233.16
	Descr: OPERATOR INITIATED-D.A. EXTRACTION STEAM EXPANSION JOINT IN LPB HOOD.							
4.	04/13/93	20:21	-	04/14/93	17:22	Forced	21.02	10,928.32
	Descr: 31 APH WON'T START.							

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #3								
5.	04/15/93	03:34	-	04/15/93	04:36	Forced	1.03	537.16
	Descr: ELECTRICAL PROTECTION DEVICES-SMF1-TRANSMISSION SYSTEM PROBLEM.							
6.	04/24/93	19:47	-	04/24/93	22:20	Forced	2.55	1,326.00
	Descr: CONTROL OPERATOR USED TURBIN TRIP BUTTON. PH DROPPED BELOW 7.0 DUE TO							
7.	05/05/93	07:55	-	05/06/93	21:04	Forced	37.15	19,318.00
	Descr: LOW VACUUM TRIP. LOSS OF 32 CIRC. WATER PUMP. 31 AND 32 C.W. PUMP DI							
8.	05/09/93	13:38	-	05/09/93	15:31	Forced	1.88	979.16
	Descr: PUCH BUTTON BY OPERATOR. CONDENSER TUBE LEAK-6.95 BOILER PH.							
9.	05/14/93	06:26	-	05/14/93	07:04	Forced	0.63	329.16
	Descr: UNIT TRIP-HIGH STEAM TEMPERATURE. UNIT CONTROL OPERATOR TRIPPED UNIT							
10.	05/19/93	07:20	-	05/19/93	08:06	Forced	0.77	398.32
	Descr: GOSHEN LINE TRIP. THE UNIT RELAYED DUE TO A BREAKER FAILURE WHEN 10H3							
11.	05/19/93	08:06	-	05/20/93	02:06	Forced	18.00	9,360.00
	Descr: UNIT OFF LINE TO REPAIR WATERWALL TUBE LEAK.							
12.	05/20/93	02:18	-	05/20/93	02:44	Forced	0.43	225.16
	Descr: HIGH TURBINE VIBRATION-SLOW LOADING. OPERATOR TRIP. REVERSE POWER AC							
13.	05/23/93	11:51	-	05/23/93	12:38	Forced	0.78	407.16
	Descr: TURBINE TRIP DEVICES. COLD REHEAT TO BOILER INTERCEPTED GREATER THAN							
14.	05/26/93	09:38	-	05/26/93	10:34	Forced	0.93	485.16
	Descr: PROTECTION DEVICES-SMF 96X.							
15.	06/14/93	09:31	-	06/14/93	10:37	Forced	1.10	572.00
	Descr: UNIT TRIP-STEAM SUPPLY TO SJAE VALVED OUT WHILE ISOLATING 32 MOISTURE							
16.	07/08/93	05:24	-	07/09/93	11:00	Forced	29.60	15,392.00
	Descr: UNIT OFF TO REPAIR S.H. PENDANT PLATEN TUBE LEAK. OPERATOR INITIATED-S							
17.	07/09/93	11:00	-	07/10/93	06:17	Forced	19.28	10,027.16
	Descr: FINISHING SUPERHEAT DESLAGGING.							
18.	07/10/93	08:04	-	07/12/93	00:00	Forced	39.93	20,765.16
	Descr: SUPERHEAT TUBE LEAK.							
19.	07/12/93	00:00	-	07/12/93	07:57	Forced	7.95	4,134.00
	Descr: LOST AUX. BREAKER TRIPPING UNIT. TURB, VENTILATOR VALVE STUCK OPEN. 7							
20.	07/24/93	23:28	-	07/25/93	22:20	Forced	22.87	11,890.32
	Descr: UNIT OFF TO REPAIR BCW SYSTEM PROBLEMS. CONTROL OPERATOR USED TURBINE							
21.	07/25/93	22:20	-	07/26/93	04:23	Forced	6.05	3,146.00
	Descr: #31 AND 32 CIRCULATING PUMPS WOULD NOT START DUE TO BAD LIMIT ON 32 CI							
22.	08/06/93	11:45	-	08/09/93	03:45	Forced	64.00	33,280.00
	Descr: R. H. PLUGGED-UNIT OFF LINE FOR DESLAGGING.							
23.	08/09/93	12:50	-	08/09/93	15:39	Forced	2.82	1,464.32
	Descr: BFP CONTROLS. BOILER CIRC. PP. DIFF.-LOW-DRUM LEVEL. #31 BFPT TRIPPE							
24.	08/10/93	04:36	-	08/10/93	05:08	Forced	0.53	277.16
	Descr: UNIT TRIPPED WHEN 31 BFP TRIPPED.							
25.	09/08/93	16:06	-	09/08/93	17:13	Forced	1.12	580.32
	Descr: UNIT TRIPPED ON TURBINE HIGH BACK PRESSURE. #31 CIRCULATING WATER PUM							
26.	09/22/93	09:10	-	09/22/93	10:36	Forced	1.43	745.16
	Descr: CONDENSER TUBE LEAK. CONTROL OPERATOR MANUALLY TRIPPED UNIT AT PHOF 7							

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #3								
27.	09/22/93	11:23	-	09/22/93	16:30	Forced	5.12	2,660.32
	Descr:	CONDENSER TUBE LEAK. UNIT TRIPPED BY OPERATOR-PH LESS THAN 7.0						
28.	09/22/93	16:30	-	09/23/93	06:44	Forced	14.23	7,401.16
	Descr:	2 BOILER TUBE LEAKS.						
29.	10/31/93	03:13	-	10/31/93	03:59	Forced	0.77	398.32
	Descr:	UNIT TRIPPED-TECH WPRKING ON P.A. FANS TRIPPED THEM.						
30.	11/04/93	14:35	-	11/04/93	17:36	Forced	3.02	1,568.32
	Descr:	CONDENSER TUBE LEAKS						
31.	11/04/93	18:21	-	11/05/93	03:55	Forced	9.57	4,974.32
	Descr:	CONDENSER TUBE LEAK						
32.	11/05/93	05:12	-	11/05/93	07:08	Forced	1.93	1,005.16
	Descr:	CONDENSER TUBE LEAKS						
		*** * * Unit Summary for Jim Bridger #3 for the year 1993 =**					431.76	224,512.60
Jim Bridger #4								
1.	01/21/93	23:34	-	01/22/93	01:54	Forced	2.33	1,213.16
	Descr:	BORAH LINE TRIPPED THEN KINPORT LINE TRIPPED UNIT 4.						
2.	01/22/93	05:49	-	01/22/93	06:34	Forced	0.75	390.00
	Descr:	GOSHEN LINT TRIPPED. UNIT WAS THE LOWEST ON LOAD.						
3.	03/12/93	22:43	-	04/13/93	00:00	Planned	744.28	387,027.16
	Descr:	PLANNED OVERHAUL.						
4.	04/13/93	00:00	-	04/16/93	00:12	Planned	72.20	37,544.00
	Descr:	CHEMICAL CLEANING.						
5.	04/16/93	00:12	-	04/18/93	15:10	Planned	62.97	32,742.32
	Descr:	POST OVERHAUL TESTING.						
6.	04/18/93	15:10	-	04/30/93	09:48	Forced	282.63	146,969.16
	Descr:	#2 BEARING VIBRATION PROBLEMS-N-2 (HP/IP MIDSPAN) SHAFT PACKING REPLAC						
7.	05/03/93	08:55	-	05/04/93	12:00	Forced	27.08	14,083.16
	Descr:	UNIT TRIP-LOSS OF DC POWER DUE TO ERROR IN LINING UP EMERGENCY POWER T						
8.	05/04/93	12:00	-	05/19/93	00:34	Forced	348.57	181,254.32
	Descr:	UNIT OUTAGE-REPAIR GENERATOR FIELD GROUND.						
9.	05/24/93	06:30	-	05/24/93	19:48	Forced	13.30	6,916.00
	Descr:	UNIT TRIPPED-MOVING BALANCE SHOTS.						
10.	05/31/93	04:05	-	06/01/93	05:45	Forced	25.67	13,346.32
	Descr:	LOWER WATERWALL TUBE LEAK.						
11.	06/05/93	22:56	-	06/07/93	13:06	Forced	38.17	19,845.80
	Descr:	WATERWALL TUBE LEAK.						
12.	06/19/93	03:40	-	06/21/93	23:37	Forced	67.95	35,334.00
	Descr:	MANUAL PUSH BUTTON BY OPERATOR. ECONOMIZER INLET VALVE PACKING AND ST						
13.	07/06/93	00:49	-	07/06/93	08:20	Forced	7.52	3,908.32
	Descr:	EHC LEAK AT #1MSSV SERVO-OPERATOR INITIATED. O-RING BETWEEN SERVO AND						
14.	07/06/93	08:20	-	07/07/93	02:39	Forced	18.32	9,524.32
	Descr:	WATERWALL TUBE LEAK.						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #4								
15.	07/07/93	23:21	-	07/08/93	19:57	Forced	20.60	10,712.00
	Descr:	WATERWALL TUBE LEAK. FLAME FAILURE DUE TO LACK OF IGNITORS. TUBE LEA						
16.	07/20/93	17:38	-	07/23/93	18:30	Forced	72.87	37,890.32
	Descr:	CONDENSER VACUUM TRIP. CONDENSER NECK EXPANSION JOINT BLOWN ON SOUTH						
17.	08/24/93	09:38	-	08/24/93	10:26	Forced	0.80	416.00
	Descr:	SWITCHYARD TRIP-500KV LINE.						
18.	08/24/93	17:23	-	08/24/93	18:00	Forced	0.62	320.32
	Descr:	C&ET LIFTED WRONG WIRE ON FSSS.						
19.	09/09/93	23:44	-	09/10/93	14:15	Forced	14.52	7,548.32
	Descr:	UNIT OFF LINE TO REPAIR BOILER TUBE LEAK.						
20.	09/10/93	14:15	-	09/10/93	23:54	Forced	9.65	5,018.00
	Descr:	REHEATER SLAG.						
21.	09/10/93	23:54	-	09/11/93	18:20	Forced	18.43	9,585.16
	Descr:	SUPERHEAT SLAG-PENDANT PLATEN AND F.S.W.						
22.	09/11/93	18:20	-	09/12/93	08:09	Forced	13.82	7,184.32
	Descr:	WATERWALL TUBE LEAK.						
23.	10/07/93	14:23	-	10/09/93	05:16	Forced	38.88	20,219.16
	Descr:	UNIT OFF LINE TO DESLAG S.H./R.H.						
24.	10/09/93	05:23	-	10/09/93	06:08	Forced	0.75	390.00
	Descr:	UNIT TRIP-LOST IGNITION ENERGY.						
25.	10/14/93	07:50	-	10/15/93	12:14	Forced	28.40	14,768.00
	Descr:	UNIT OFF LINE TO REPAIR FSH TUBE LEAK.						
26.	10/26/93	08:07	-	10/26/93	14:31	Forced	6.40	3,328.00
	Descr:	UNIT TRIP-SUSPECT ELECTRICAL PROBLEM IN EHC MANUAL TRIP CIRCUIT.						
27.	11/13/93	01:07	-	11/14/93	00:23	Forced	23.27	12,098.32
	Descr:	PHOSPHATE INJECTION LINE LEAK						
		*** * * Unit Summary for Jim Bridger #4 for the year 1993 =**					1,960.75	***,***.**
Little Mtn.								
1.	01/02/93	06:20	-	01/02/93	20:35	Forced	14.25	199.50
	Descr:	UNABLE TO STARTUP DUE TO UNKNOWN SHORT IN WIRING AND OTHER RELATED ITE						
2.	02/18/93	07:45	-	02/18/93	18:55	Maint.	11.17	156.32
	Descr:	UNIT REMOVED FORM SERVICE BECAUSE OF EXCESSIVE VIBRATION IN NO. 1 BEAR						
3.	06/08/93	11:30	-	06/08/93	14:00	Forced	2.50	35.00
	Descr:	ATTEMPTED TO REPAIR FLAME DETECTOR AND UNIT TRIPPED						
4.	07/22/93	07:00	-	08/23/93	15:30	Planned	776.50	10,871.00
	Descr:	BOILER OVERHAUL						
5.	11/02/93	09:10	-	11/02/93	10:12	Maint.	1.03	14.46
	Descr:	UNIT WAS TAKEN OFF-LINE DUE TO EXCESSIVE VIBRATION OF #1 BEARING						
6.	11/03/93	11:30	-	11/03/93	16:00	Forced	4.50	63.00
	Descr:	#1 BEARING VIBRATION - EXCESSIVE						
7.	11/03/93	16:15	-	11/03/93	17:20	Forced	1.08	15.16
	Descr:	CONTROL PROBLEMS WITH THE UNIT						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Little Mtn.								
8.	11/22/93	11:30	-	11/22/93	12:00	Forced	0.50	7.00
	Descr:	INSULATOR FAILURE CAUSED A POLE FIRE AND TOOK THE UNIT OFF-LINE						
9.	11/22/93	12:00	-	11/22/93	15:50	Forced	3.83	53.66
	Descr:	THE ACCESORY GEAR COUPLING WAS REPAIRED WHICH IS RELATED TO THE #1 BEA						
10.	11/30/93	12:30	-	11/30/93	17:00	Forced	4.50	63.00
	Descr:	MACHINE TRIPPED ON EXHAUST GAS DIFFERENTIAL						
	*** * * Unit Summary for Little Mtn. for the year 1993 =**						819.86	11,478.10
Naughton #1								
1.	01/27/93	06:32	-	01/27/93	12:30	Forced	5.97	954.56
	Descr:	EXCITER TRIP, OPERATOR WASHING DECK						
2.	04/14/93	04:05	-	04/15/93	12:40	Forced	32.58	5,213.28
	Descr:	WATERWALL TUBE LEAK						
3.	05/27/93	00:47	-	05/27/93	15:36	Forced	14.82	2,370.56
	Descr:	LOW BOILER PH						
4.	06/10/93	10:19	-	06/10/93	11:36	Forced	1.28	205.28
	Descr:	ENGINEERING ERROR IN CHECKING EXCITER CONTACTS						
5.	07/02/93	23:44	-	07/03/93	03:29	Forced	3.75	600.00
	Descr:	230KV TRANSMISSION LINE FAULT						
6.	07/03/93	08:06	-	07/03/93	21:43	Forced	13.62	2,178.56
	Descr:	230 KV TRANSMISSION LINE FAULT, 201CB TRIPPING SCHEME TROUBLESHOOTING						
7.	07/18/93	00:00	-	07/19/93	16:48	Forced	40.80	6,528.00
	Descr:	WATERWALL TUBE LEAK REPAIRS						
8.	09/13/93	00:39	-	09/15/93	08:13	Forced	55.57	8,890.56
	Descr:	AUX BRKR TRIPPED, WATER DRIPPING ON 1-4 MILL BRKR FROM DOM WTR SYS						
9.	09/25/93	00:30	-	09/29/93	01:12	Forced	96.70	15,471.84
	Descr:	UNIT TRIP - ROOF WW TUBE LEAK						
10.	10/31/93	05:12	-	11/04/93	05:33	Forced	96.35	15,416.00
	Descr:	EXCITER FAULT						
	*** * * Unit Summary for Naughton #1 for the year 1993 =**						361.44	57,828.64
Naughton #2								
1.	02/21/93	23:57	-	02/24/93	02:12	Forced	50.25	10,552.50
	Descr:	CONDENSER TUBE LEAK; BURNER TILT PROBLEMS						
2.	05/30/93	11:29	-	05/30/93	13:35	Forced	2.10	441.00
	Descr:	STATOR COOLING PUMP BREAKER FAILED AND TRIPPED THE UNIT OFF-LINE						
3.	07/02/93	23:44	-	07/03/93	05:25	Forced	5.68	1,193.43
	Descr:	230KV LINE DISTRIBUTION FAULTS						
4.	07/03/93	08:05	-	07/03/93	15:22	Forced	7.28	1,529.43
	Descr:	TRIPPED WITH MAIN STEAM STOP VALVE						
5.	07/29/93	08:18	-	07/29/93	09:00	Forced	0.70	147.00
	Descr:	GEN TRIP RELAY AUX 205X BEHIND CONSOLE WAS BUMPED - NO COVER						
6.	07/29/93	09:00	-	07/30/93	16:06	Maint.	31.10	6,531.00
	Descr:	MAINT REPAIRS OF TUBE LEAK						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Naughton #2								
7.	09/17/93	22:53	-	09/20/93	05:17	Maint.	54.40	11,424.00
	Descr:	CONDENSER TUBE LEAK, BURNER TILT REPAIR, SANDBLAST PRECIP						
8.	10/03/93	00:11	-	10/03/93	21:54	Forced	21.72	4,560.36
	Descr:	CONDENSER TUBE LEAK REPAIRS						
9.	10/16/93	16:48	-	10/18/93	08:41	Forced	39.88	8,375.43
	Descr:	REBUILD LEAKING MAIN STEAM SAFETY RELIEF VALVE						
10.	10/22/93	00:14	-	10/22/93	16:51	Forced	16.62	3,489.36
	Descr:	CONDENSER TUBE LEAK REPAIRS						
	*** * * Unit Summary for Naughton #2 for the year 1993 =**						229.73	48,243.51
Naughton #3								
1.	01/05/93	01:50	-	01/06/93	16:31	Forced	38.68	12,765.39
	Descr:	2 WATERWALL TUBE LEAKS; CONDENSER VACUUM LEAK (2 DRAIN LINES ROTTED OF						
2.	01/06/93	17:53	-	01/06/93	19:44	Forced	1.85	610.50
	Descr:	CONDENSER VACUUM LEAK						
3.	01/08/93	22:19	-	01/09/93	14:42	Forced	16.38	5,406.39
	Descr:	CONDENSER LEAK						
4.	01/19/93	23:27	-	01/21/93	10:35	Forced	35.13	11,593.89
	Descr:	REHEAT AND WATERWALL TUBE LEAK; REPAIRED 3-3 COAL PIPES						
5.	02/03/93	01:16	-	02/05/93	19:34	Forced	66.30	21,879.00
	Descr:	REPAIRED 5 WATERWALL TUBE LEAKS, 2 REHEAT TUBE LEAKS						
6.	02/05/93	22:51	-	02/06/93	17:07	Forced	18.27	6,027.78
	Descr:	BOILER FEED PUMP PROBLEMS - WATER IN OIL						
7.	02/26/93	00:26	-	02/27/93	20:32	Forced	44.10	14,553.00
	Descr:	REHEATER AND WATERWALL TUBE LEAKS						
8.	02/28/93	00:53	-	03/04/93	19:59	Forced	115.10	37,983.00
	Descr:	11 REHEATER/1 WATERWALL TUBE LEAKS(BTF 25-36 RPTS)						
9.	03/13/93	22:38	-	03/15/93	02:42	Forced	28.07	9,261.78
	Descr:	FRONT REHEATER PENDANT LEAK						
10.	03/24/93	03:05	-	03/25/93	07:44	Forced	28.65	9,454.50
	Descr:	WATERWALL & FRONT REHEAT PENDANT LEAKS						
11.	03/28/93	09:41	-	03/31/93	11:41	Forced	74.00	24,420.00
	Descr:	REHEAT TUBE LEAK						
12.	03/31/93	21:02	-	04/01/93	22:12	Forced	25.17	8,304.78
	Descr:	UNIT TRIP BOILER PH OUT OF LIMITS						
13.	04/02/93	06:42	-	04/04/93	01:43	Forced	43.02	14,195.28
	Descr:	REHEAT TUBE LEAK						
14.	04/05/93	14:52	-	04/05/93	18:18	Forced	3.43	1,132.89
	Descr:	BOILER PH BAD						
15.	04/11/93	23:35	-	04/12/93	14:36	Forced	15.02	4,955.28
	Descr:	CONDENSER TUBE LEAK						
16.	04/24/93	00:03	-	05/28/93	15:00	Planned	830.95	274,213.50
	Descr:	MAJOR BOILER, MAJOR GENERATOR, MINOR TURBINE OVERHAUL						

1993 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Naughton #3							
17.	06/01/93	00:00	06/02/93	13:01	Planned	37.02	12,215.28
	Descr: MAJOR BOILER/GENERATOR, MINOR TURBINE OVERHAUL						
18.	06/02/93	13:13	06/03/93	02:43	Forced	13.50	4,455.00
	Descr: UNIT TRIP FOLLOWING STARTUP AFTER OH						
19.	06/03/93	10:00	06/04/93	00:30	Forced	14.50	4,785.00
	Descr: WATERWALL TUBE LEAK; ALSO TURBINE VIBRATIONS						
20.	06/24/93	10:41	06/27/93	17:36	Forced	78.92	26,042.28
	Descr: HYDROGEN LEAK ON TURBINE-GENERATOR						
21.	07/02/93	23:44	07/04/93	13:33	Forced	37.82	12,479.28
	Descr: 230KV TRANSMISSION LINE FAULT & REPAIRED BOILER TUBE LEAKS						
22.	07/28/93	10:42	07/28/93	12:18	Maint.	1.60	528.00
	Descr: SOUTHSIDE AQUARIAN WAS VALVED OUT & IN; BROUGHT IN TRANSMITTER RELAYS						
23.	07/29/93	11:08	07/31/93	00:41	Maint.	37.55	12,391.50
	Descr: REHEAT & RIGHT SIDEWALL TUBE LEAK REPAIRS						
24.	08/27/93	23:55	08/30/93	08:36	Maint.	56.68	18,705.39
	Descr: REPAIR 1 RH TUBE LEAK & 1 WATERWALL TUBE LEAK						
25.	09/22/93	23:07	09/25/93	07:43	Maint.	56.60	18,678.00
	Descr: SPACERS REPLACED ON REHEAT SHIELDS BY CONTRACTOR						
26.	10/19/93	23:10	10/20/93	02:00	Forced	2.83	934.89
	Descr: UNIT TRIP - HIGH DRUM LEVEL						
27.	10/25/93	13:37	10/25/93	14:30	Forced	0.88	291.39
	Descr: TRIP; LOW DRUM LEVEL TRIP RELAY						
28.	11/17/93	12:30	11/17/93	22:22	Forced	9.87	3,255.78
	Descr: LOW DRUM PH						
29.	12/29/93	18:57	12/30/93	12:24	Forced	17.45	5,758.50
	Descr: UNIT OFF- DRUM PH 6.6 & FALLING						
	*** **Unit Summary for Naughton #3 for the year 1993 =**					1,749.34	577,277.25
Wyodak							
1.	06/26/93	11:15	06/27/93	19:48	Forced	32.55	10,416.00
	Descr: SECONDARY SUPERHEATER TUBE LEAK, FAILURE MODE - LONG TERM OVERHEAT.						
2.	06/27/93	19:48	06/27/93	21:18	Forced	1.50	480.00
	Descr: LIGHTER PROBLEMS DELAYED START-UP OF UNIT.						
3.	06/28/93	15:14	06/29/93	20:36	Forced	29.37	9,397.12
	Descr: TUBE LEAK IN PRIMARY SUPERHEATER. FAILURE MODE - SOOT BLOWER EROSION.						
4.	06/29/93	20:36	06/29/93	21:36	Forced	1.00	320.00
	Descr: UNIT START-UP DELAYED DUE TO LIGHTER PROBLEMS.						
5.	10/01/93	03:20	10/01/93	07:38	Forced	4.30	1,376.00
	Descr: UNIT TRIPPED ON LOW FURNACE PRESSURE						
6.	12/04/93	12:36	12/04/93	14:46	Forced	2.17	693.12
	Descr: MAINTENANCE PROCEDURE CONTROL ELECTRICIAN CALIBRATING TURBINE FIRST						
	*** **Unit Summary for Wyodak for the year 1993 =**					70.89	22,682.24

Sch. 36

Program	"Participant Description"	Conservation "Unit" Description	1993 Participants	1993 Units Acquired / Processed
Zero Interest Program	Any Single-Family home owner with permanently connected electric heat. Must meet minimum credit approval. Will be rolled into SGC Home Improvment in 1994.	Homes Weatherized	7	7
Low Income Program	Any residence with electric heat as the primary heat source. Must meet income requirement: 125% of Federal poverty level.	Homes Weatherized	54	54
Efficient Heat Pumps	Small Commercial or Residential customers with 1.5 - 7.5 ton Heat Pump installed by an H-Pro dealer. Must have HSPF standard >= 7.0	Heat Pump: Air to Air or Ground Source	16	16
Efficient Water Heaters	Any Single Family home owner may sign up for Hassle Free program which pays for replacement of their electric water heater with a more efficient one if it fails.	Water Heaters Replaced	142	142
Super Good Cents Home Improvement Program	Any existing residential home with electric heat as primary heat source. Zero Interest Program to be rolled into this program in 1994.	Homes Weatherized to Super Good Cents Standards	0	0
Super Good Cents	Any builder or owner of a New residential electrically heated home in Pacific Power's Montana service territory.	New Homes	51	51
Manufactured Acquisition Prgm	Manufacturers of electrically heated manu-factured homes built to standards which exceed HUD.	New Manufactured Homes	96	96
Energy FinAnswer	Owners or developers of new Commercial buildings or new addtions over 12,000 square feet.	Square Footage of treated space	0	0
Energy FinAnswer 12,000	Owners or developers of new Commercial buildings or new additions under 12,000 square feet, and warehouses.	Square Footage of treated space	0	0

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Sch. 36	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS									
		('94) Current Year	('93) Last Year		Planned Savings - 1994		Achieved Savings - 1993		Difference	
	Program Description	Expenditures	Expenditures	% Change	(MWa)	(MWh)	(MWa)	(MWh)	(MWa)	(MWh)
1	Zero Interest Program									
2	Initiated - 1978	$0	$8,371	NA	0.00	0	0.01	49	-0.01	-49
3	Projected Life - to be rolled into SGC HIP in 1994									
4	Low Income Program									
5	Initiated - 1987	$34,342	$65,644	52%	0.00	29	0.01	116	-0.01	-87
6	Projected Life - Indefinite									
7	Efficient Heat Pumps									
8	Initiated - 1986	$6,343	$2,421	262%	0.00	11	0.00	8	0.00	3
9	Projected Life - Indefinite									
10	Efficient Water Heaters									
11	Initiated - 1987	$6,854	$9,043	76%	0.00	41	0.01	50	0.00	-9
12	Projected Life - Indefinite									
13	Super Good Cents Home Improvement Pgm									
14	Initiated - 1993	$34,328	$0	NA	0.01	109	0.00	0	0.01	109
15	Projected Life - Indefinite									
16	Super Good Cents									
17	Initiated - 1988	$92,990	$172,101	54%	0.01	127	0.02	194	-0.01	-67
18	Projected Life - Indefinite									
19	Manufactured Acquisition Program (MAP)									
20	Initiated - 1991	$75,115	$178,094	42%	0.03	288	0.13	1,115	-0.09	-827
21	Projected Life - Indefinite									
22	Energy FinAnswer									
23	Initiated - 1991	$25,955	$8,685	299%	0.01	76	0.00	0	0.01	76
24	Projected Life - Indefinite									
25	Energy FinAnswer 12,000									
26	Initiated - 1992	$20,452	$35,723	57%	0.01	68	0.00	0	0.01	68
27	Projected Life - Indefinite									
28										
29										
30										
31										
32		$296,379	$480,082	62%	0.09	749	0.17	1,532	-0.09	-783

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